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 91** **APPROVED:** MAR 28 2012

ORDER OF THE COMMISSION

Presiding Officers:
Kari A. E. Bennett, Commissioner
Aaron A. Schmoll, Senior Administrative Law Judge

On January 26, 2012, 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 adjustment charge ("FAC") for electric service, approval of a change in its FAC for steam service, and to update monthly benchmarks, together with its case-in-chief testimony.

On January 30 and February 2, 2012, respectively, Steel Dynamics, Inc. ("SDI") and Duke Energy Indiana Industrial Group ("Industrial Group") filed Petitions to Intervene in this proceeding. On February 22, 2012, Duke Energy Indiana filed supplemental testimony. The Indiana Office of Utility Consumer Counselor ("OUCC") filed its audit report and direct testimony on March 1, 2012. On March 6, 2012, Duke Energy Indiana filed its rebuttal testimony, which included a procedural settlement agreement between the Company and SDI.

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 March 12, 2012, at 10:15 a.m., in Room 224 of the PNC Center, 101 West Washington Street, Indianapolis, Indiana. Duke Energy Indiana and the OUCC offered their respective prefiled testimony and exhibits into the evidentiary record without objection. The Presiding Officers granted the 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. **Notice and Commission 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 Ind. 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 17, 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 ("Constrution Work in Progress (CWIP) Order"), and subsequent update Orders up to and including the July 27, 2011, update in Cause No. 42061 ECR 17 ("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 ECR3 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 November 30, 2011, to be $406,624,000. No evidence was offered objecting 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, provided direct testimony regarding Duke Energy Indiana's fuel procurement practices. Mr. Batson testified that during the twelve month period ended November 30, 2011, coal purchased under long-term commitments comprised greater than 97% of total coal receipts. 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. He testified that the vast majority of spot coal purchased during the twelve-month period was for Gallagher Station.

Mr. Batson testified that due to increasingly lower power prices and reduced demand for coal generation, Duke Energy Indiana's coal burn projections for 2012 have been adjusted downward. Based on the low actual burns for December 2011 and the downward projection for coal burns in 2012 as compared against the amount of coal under contract for delivery in 2012, the Company expects coal inventories at all of its Indiana stations to increase during 2012. Mr. Batson testified that there will likely be further upward pressure on the Indiana coal inventory if mild weather continues. Mr. Batson testified that the Company entered into an agreement with an Indiana supplier for low sulfur coal to be delivered in 2012 for purposes of compliance with the Cross-State Air Pollution Rules ("CSAPR"). With the stay issued by the U.S. Appeals Court in Washington D.C. of the implementation of CSAPR, the Company is evaluating options for managing these low sulfur coal deliveries. Mr. Batson testified that inventories for the Company's coal fired plants remain near normal levels, with the exception of the continued existence of the Gibson remote pile. He stated that relevant to this FAC period, inventories on the Gibson Station main pile were at or near target levels; however, since early December, inventories have increased and are now above target levels. He testified that the overall rising inventory at Gibson Station beginning in December is due to reduced generation over the period as a result of a number of factors, including declining power prices and extremely mild weather. Mr. Batson testified that the Company continues to manage the transfer of coal from the Gibson Station remote pile to its main pile in such a way as to best manage fuel costs for the customers.

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 September through November 2011 decreased from a high of approximately $4.00 per million BTU to a low of $3.50 per million BTU. Mr. Swez testified that, in his opinion, Duke Energy Indiana purchased natural gas at the lowest cost reasonably possible.

In supplemental testimony, Mr. Batson testified that coal inventories continue to increase. He stated that from December 1, 2011 through February 15, 2012, the Company's coal inventories increased by approximately 800,000 tons, a period of time in which historically inventories have decreased across the system. He testified that extremely low natural gas prices and unseasonably mild weather for the period of December 2011 through mid-February 2012 have caused the power prices in MISO to drop. In turn, the Company's coal generating facilities have experienced much lower dispatch levels as well as periods of economic shutdown. Mr. Batson testified that this was an unexpected change in the market and has led to a significant increase in coal inventories. He stated that based on forecast natural gas prices and electric prices, the Company has a reasonable expectation of significant coal inventory growth throughout the remainder of 2012 and likely into 2013. Mr. Batson explained that the sharp decline in natural gas prices has allowed generation from combined cycle natural gas units to become increasingly competitive with coal units. He testified that for the months of December and January, the Indiana coal-fired generation stations consumed approximately 45% and 40% less coal than consumed during the same two-month period in 2009 and 2010, respectively. The Company forecasts that the annual coal burns for Indiana in 2012 will be as much as 40% lower than the coal burns for calendar year 2011.

Mr. Batson testified that due to the lower burn projections for the remainder of 2012, the Company projects that its inventories will continue to grow steadily and will exceed maximum storage capacity for coal at its stations in the very near future. Mr. Batson testified that Duke Energy Indiana is undertaking and continuing to evaluate a host of options in order to effectively manage the growing inventories, such as (i) meeting with long-term suppliers to discuss deferral, cancellation and other commercial and operational options to decrease the shipments for 2012; (ii) commissioned and completed a survey to determine the maximum storage capabilities at all of its stations; (iii) begun to prepare the existing Gibson Remote Pile for additional storage of coal; (iv) explored options to increase the storage capabilities at both on-site and off-site facilities, including a possible second Gibson Remote pile; (v) exploring options to resell surplus coal into the market; (vi) implementing a decrement to coal pricing inputs used to formulate supply offers to MISO; and (vii) considering its options to buy-out of existing contracts or to pursue other legal options. Mr. Batson testified that the Company will continue to closely monitor its anticipated coal requirements and inventories and take every action available to cost effectively control coal inventories in the least cost-impact manner for customers.

OUCC witness Mr. Michael D. Eckert, Senior Utility Analyst, 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 among the lowest. Mr. Eckert also testified that he prepared a schedule that 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. Finally, Mr. Eckert recommended that Duke Energy Indiana continue to update the Commission on its coal inventory.

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 92 proceeding as recommended by the OUCC.

6. Hedging Activities. 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 90 proceeding, the Company purchased February and March 2012 forward natural gas contracts to hedge up to 100% of the Company's expected native burn for January and February 2012. Mr. Chen discussed the results of the gas hedging for the September through November 2011 reconciliation period. He testified that the Company realized a loss of $87,296 from hedges bought for August 2011 native gas burn and paid $61 in broker commissions in October 2011.

Mr. Chen discussed the results of and the factors influencing the results of the power hedging for the September through November 2011 reconciliation period. He stated the Company experienced realized power hedging losses (exclusive of Midwest Independent Transmission System Operator, Inc. ("Midwest ISO") virtual trades and including prior period adjustments) for the period of $45,353.

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 (meeting most recently with the OUCC on July 12, 2011), has responded to all data requests, and has provided hedging audit information for the reconciliation months of this FAC filing.

Mr. Chen stated 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.

Mr. Blackwell explained that the amount included in fuel costs for hedging activity in this proceeding was a realized loss of $87,357 for gas hedging activity and a realized net loss of $45,353 for power hedging activity (exclusive of Midwest ISO virtual activity and including prior period adjustments).

OUCC witness Mr. Eckert testified that there were no major issues related to hedging in this cause. He noted that the OUCC issued a data request regarding hedging and intends to discuss the responses with representatives from the Company, as appropriate, 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 loss of $87,357 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 evidence was offered in this Cause noting issues with the realized net gain for power hedging included in the fuel costs in this proceeding or challenging 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 Settlement. Thus, we will allow Petitioner to include $45,353 of realized power hedging losses 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 FAC77 and Cause No. 38707 FAC80.

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 September, October and November 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)	Sept-11	Oct-11	Nov-11
Regulation Cost Dist	0.0723	0.0814	0.0663
Spinning Cost Dist	0.0388	0.0490	0.0304
Supplemental Cost Dist	0.0231	0.0198	0.0137

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. <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 testified that there were a number of operating conditions that affect the dispatch of Petitioner's operating units. He testified that low natural gas prices and mild weather have caused the energy price in the MISO market to drop, causing Duke Energy Indiana's coal generating facilities to experience lower dispatch levels and even periods of economic shutdown. He stated that natural gas units are frequently the marginal unit, meaning the last unit committed or dispatched, and can be correlated to the MISO energy price. He explained that as natural gas prices have dropped, the MISO energy price has dropped, resulting in lower dispatch levels for the Company's coal units.

Mr. Swez testified that as a result of the Federal Court of Appeals blocking implementation of CSAPR, no change in dispatch and commitment of the Company's units has occurred due to the CSAPR rules. CSAPR creates four new interstate trading markets, of which Indiana is a member of three. He explained that these three markets are for Annual NOx, Seasonal NOx, and Group 1 SO_2 allowances. He testified that the allocation levels associated with this rule will require a significant reduction in emissions and the market prices associated with the allowances are likely to be considerably higher than emission allowance prices seen in recent years. Mr. Swez testified that the Company's preliminary model runs under CSAPR show significant reductions in capacity factor are possible at non-scrubbed generating units. He reiterated that these results are preliminary and significant changes in forecasted capacity factors could occur by changing data inputs.

In supplemental testimony, Mr. Swez testified that uncharacteristically low natural gas prices and unseasonably mild weather, among other factors, have caused power prices in the MISO market to drop, causing Duke Energy Indiana's coal generating facilities to experience lower dispatch levels as well as periods of economic shutdown. He testified that absent the implementation of a price decrement to the Company's dispatch and commitment price of its units, the Company is projecting inventory levels will exceed maximum storage levels until at least the end of 2013. Mr. Swez testified that the price decrement represents the avoided cost associated with implementing a more expensive option to avoid or reduce surplus coal inventories, such as buying out of a coal contract, reselling the coal, or taking some other form of action. He stated that the dispatch and commitment costs of the appropriate coal units are reduced by the costs that would be avoided if the unit would be cleared and dispatched by MISO. He testified that given the additional costs associated with avoiding or reducing surplus coal inventories, Duke Energy Indiana believes it makes sense to try to avoid some of these costs by offering the units with the decremental price subtracted from the current offer cost. He explained that to the extent the units are dispatched, coal coming to the station is consumed, other potential costs are avoided, and customers ultimately benefit. Mr. Swez stated that this is very similar to the manner in which the Company successfully economically dealt with a surplus coal inventory situation at Gallagher Station in 2009, as approved in Cause No. 38707 FAC82.

In explaining how the price decrement would be applied to the Company's supply offers, Mr. Swez testified that for all of the Company's coal generating stations with the exception of Gallagher Station (which burns a different quality of coal than the rest of the portfolio and is currently not in an oversupply position), the supply offer would be calculated just as it would normally, except that the price of coal would be reduced by the price decrement. He stated that supply offers would continue to be calculated and updated each day for each hour of the day-ahead and real-time markets. In explaining how the amount of the initial decrement will be determined, Mr. Swez testified that all available options for dealing with surplus tons were assigned a cost and volume. He testified that the decrement is determined by stacking the options from least cost to highest cost and using the option at the level of volume in the stack that is associated with the total oversupply. These options, as described in Mr. Batson's supplemental testimony, currently include on-site coal storage, storing coal at coal supply mines, reselling the coal, and buying out coal contracts. Mr. Swez went on to explain that the inputs to this calculation will be updated twice per month. He stated that this includes updating the cost and volume for the various options for dealing with the surplus tons, as well as the model used to project the surplus inventory. Mr. Swez testified that the projections show that the decrement price used will drop substantially over time. Mr. Swez testified that the fact that the Company is using a decrement based on the highest cost option to deal with the surplus coal in formulation of the generating units offer does not mean that the Company will physically implement this option. He stated that the decrement represents the additional cost that is being avoided when an additional ton of coal is consumed. Thus, burning more coal will always allow the Company to avoid the most expensive option. He stated that instead, the Company will actually physically implement the least expensive options. Mr. Swez testified that the use of a decrement will not affect the Company's adherence with the rules of the MISO market and will be in the best interest of the Company's customers. Mr. Swez testified that the Company is not requesting any specific approvals from the Commission, but wanted to notify the Commission, the OUCC, and the intervening parties of its growing inventory and its plans to mitigate it, including its implementation of the avoided cost decrement pricing.

Mr. Eckert testified that the OUCC did not have adequate time to review the Company's request regarding the proposed coal decrement pricing and the potential issues associated with it. The OUCC recommends that the Commission defer a finding on the coal decrement pricing issue until Duke Energy Indiana's next FAC.

In rebuttal testimony, Mr. Blackwell responded that Duke Energy Indiana is not requesting Commission approval of the price decrement so it is not necessary for the Commission to issue a finding in this proceeding or to agree to defer such finding to the next FAC. He stated that the Company was simply notifying the Commission and parties of its growing inventory and its plans to mitigate its growing inventory, including its implementation of the avoided cost decrement pricing. Mr. Blackwell testified that the Company will provide an update to the Commission and the parties in the next FAC regarding the status of the avoided cost decrement.

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. Major Forced Outages. In the December 28, 2011 Order in Cause No. 38707 FAC90, the Commission ordered Duke Energy Indiana to discuss in future FAC proceedings major forced outages of units of 100 MW or more lasting more than 100 hours. Mr. Swez testified that on October 13, 2011 at 1700 EST, Wheatland 4, a unit with a seasonal adjusted capacity of 119 MW, was forced off-line due to cracking found at a basket in the combustion section of the turbine. He stated that the basket was sent out for repairs and subsequently replaced, resulting in the unit returning to availability on November 4, 2011, at 0834. Mr. Swez testified that this was the only such forced outage between September through November 2011.

10. **New Source Review ("NSR") Litigation Impacts on Operations.** Mr. Swez noted 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 2011. Mr. Swez also testified that pursuant to the Consent Decree, the Company was required to make a final decision by January 1, 2012, concerning whether Gallagher Units 1 and 3 would be converted to gas or retired. Mr. Swez advised that as a result of the Company receiving Commission approval for the purchase of a portion of a merchant plant from Duke Energy Vermillion II, LLC in Cause No. 43956, the decision was made to retire these units. Mr. Swez stated that Gallagher Units 1 and 3 were retired at the end of January 2012. Mr. Swez testified that the additional capacity from acquiring Vermillion II, LLC is slightly larger than the lost capacity from retiring Gallagher units 1 and 3.

OUCC witness Mr. Eckert recommended that in its next FAC proceeding, Duke Energy Indiana update the Commission on how the shutdown of two Gallagher units and the acquisition of the merchant plant from Duke Energy Vermillion II, LLC, will impact the Company's actual and forecasted costs. He also recommended that in its next FAC proceeding, Duke Energy Indiana update the Commission on what it plans to do with the two retired generating units at Gallagher Station.

11. **Procedural Agreement with SDI.** Mr. Blackwell testified that SDI requested additional time to serve data requests on Duke Energy Indiana on issues relevant to the FAC91 proceeding until the filing of the Company's next FAC proceeding. He further testified that SDI has requested that the Company agree to the approved fuel factor in FAC 91 being subject to refund until the issuance of the later of the final order in FAC 92 or in a subdocket (if any) initiated in FAC92. Duke Energy Indiana and SDI have agreed to enter into an Agreement as to Procedures for FAC 91 and FAC 92 ("Agreement") for the sole purpose to establish procedures for the FAC 92 proceeding. Mr. Blackwell indicated that the other parties to the proceeding have no objections to this Agreement. The Commission approves this procedural agreement, and accordingly, we find that the fuel factor approved herein is subject to refund until the issuance of the later of the final order in FAC 92 or in a subdocket initiated in FAC 92.

12. **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 November 30, 2011. Duke Energy Indiana's authorized jurisdictional operating expenses (excluding fuel costs) are $815,321,000. For the 12-month period ended November 30, 2011, Duke Energy Indiana's jurisdictional operating expenses (excluding fuel costs) totaled $1,168,329,000. 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.

13. **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 that 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.

Mr. Blackwell 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 November 30, 2011. During this period, Duke Energy Indiana's actual jurisdictional electric operating income level was $257,687,000, while its authorized phased-in jurisdictional electric operating income level for purposes of Indiana Code § 8-1-2-42(d)(3), was $406,624,000. Therefore, the Commission finds that Duke Energy Indiana did not earn a return in excess of its authorized level during the 12 months ended November 30, 2011.

14. **Estimation of Fuel Costs.** Duke Energy Indiana estimates that its prospective average fuel cost for the months of April through June 2012 will be $76,102,540 or $0.030578 per kWh. Duke Energy Indiana previously made the following estimates of its fuel costs for the period September through November 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
September 2011	28.203	26.245	7.46
October 2011	27.416	26.668	2.80
November 2011	28.540	26.773	6.60
Weighted Average	28.050	26.561	5.61

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 5.61%. Duke Energy Indiana's estimating techniques appear reasonably sound and its estimates for April through June 2012 should be accepted and we so find.

15. **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
September 2011	226.86	Wabash River Diesel
October 2011	46.51	Madison 2
November 2011	277.37	Connersville 1

1/ Calculated using most efficient unit heat rate.

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 September through November 2011 reconciliation period.

16. **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 April through June 2012 billing cycles is computed as follows:

	$ / kWh
Projected Average Fuel Cost	0.030578
Net Variance (current reconciliation period)	0.001626
Remaining FAC 90 Variance	0.001634
Adjusted Fuel Cost Factor	0.033838
Less: Base Cost of Fuel	0.014484
Fuel Cost Adjustment Before Applicable Taxes	0.019354
Adjustment for Utility Receipts Tax	0.000295
Fuel Cost Adjustment Factor Adjusted for Applicable Taxes	0.019649

The net variance factor shown above reflects $10,324,089 of under-billed fuel costs applicable to retail customers that occurred during the period of September through November 2011. The factor computation also includes $10,377,569, which reflects the remaining portion (one-half) of the FAC 90 variance that the Company was authorized to collect over a six-month period instead of the normal three-month recovery period. The Commission approved this treatment in Cause No. 38707 FAC 90.

OUCC witness Mr. Gregory Guerrettaz, President, Financial Solutions Group, Inc., 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 November 30, 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, Post Analysis Cost Evaluation ("PACE"), and source documentation of the Company for the period reviewed.

17. **Effect on Residential Customers.** The approved factor represents an increase of $0.001274 per kWh from the factor approved in Cause No. 38707 FAC 90. The typical residential customer using 1,000 kWhs per month will experience an increase of $1.27 or 1.4%

on his or her base electric bill compared to the factor approved in Cause No. 38707-FAC90 (excluding various tracking mechanisms and sales tax).

18. **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.

19. **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 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.[1] The fuel cost adjustment factor for Temple-Inland of $1.6201953 per 1,000 pounds of steam was calculated on Exhibit B, Schedule 1, of the Verified Application; this factor will be effective for the April through June 2012 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 $16,286 payable to Temple-Inland for the months of September through November 2011.

The Commission finds that Duke Energy Indiana's proposed fuel cost adjustment factor for Temple-Inland of $1.6201953 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 $16,286 payable to Temple-Inland has been properly determined and should be approved.

20. **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. 13, Duke Energy Indiana did not have excess earnings for the 12 months ended November 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. 16, and the fuel cost adjustment for steam service as set forth in Finding No. 18 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.

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[1] On January 25, 2012, this Commission issued an Order approving the fourth amendment to Steam Supply Agreement between Duke Energy Indiana and Temple-Inland, Inc., which will be reflected in Petitioner's next FAC filing.

3. Duke Energy Indiana shall place into effect the fuel cost adjustment factors for electric service and steam service approved herein, applicable to all bills rendered beginning with and subsequent to the later of the effective date of the Commission's Order or the first billing cycle of April 2012, 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. The Procedural Agreement entered into between Duke Energy Indiana and SDI is hereby approved.

5. Duke Energy Indiana shall provide an update on the status of its coal inventories in FAC 92, as described in Finding No. 5 of this Order.

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

ATTERHOLT, BENNETT, LANDIS, MAYS AND ZIEGNER CONCUR:

APPROVED: MAR 28 2012

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