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 81) APPROVED: SEP 23 2009

BY THE COMMISSION:
David E. Ziegner, Commissioner
Loraine L. Seyfried, Administrative Law Judge

On August 4, 2009, 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.

Petitions to Intervene were filed by Steel Dynamics, Inc. ("SDI"), Nucor Steel-Indiana, a division of Nucor Corporation ("Nucor"), and Duke Energy Indiana Industrial Group ("Industrial Group"), which the Presiding Officers granted by docket entry. The Indiana Office of Utility Consumer Counselor ("OUCC") filed its audit report and direct testimony on September 8, 2009. On September 9, 2009, the Commission issued a docket entry to the Company inquiring about its accounting treatment of coal storage and reclaim costs. On September 11, 2009, Duke Energy Indiana responded to the Commission's docket entry inquiry.

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 September 15, 2009, at 10:00 a.m., in Room 224, of the National City Center, 101 West Washington Street, Indianapolis, Indiana. Duke Energy Indiana offered into evidence its Verified Application in this Cause, including exhibits thereto, and the direct verified testimonies, including corresponding exhibits, of Ms. Mary Ann Amburgey, Mr. Scott A. Burnside, Ms. Diana L. Douglas, Mr. Stephen M. Herrera, Ms. Diane L. Jenner, Mr. Vincent E. Stroud, and Mr. John D. Swez. Duke Energy Indiana also offered the rebuttal testimony of Ms. Diana L. Douglas. The OUCC offered the testimonies and exhibits of Mr. Gregory T. Guerrettaz and Mr. Michael D. Eckert. All evidence and exhibits were admitted into the record without objection. Ms. Douglas also responded to questions by the Presiding Officers at the 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 Jurisdiction and Notice.** 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, *et seq.*, 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, Premier Boxboard Limited LLC ("Premier").

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 Indiana 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 ECR3 through 42061 ECR12, the November 20, 2007 Order in Cause Nos. 43114 and 43114-S1 ("IGCC Order") and the Orders in Cause No. 43114 IGCC1 and IGCC2.** 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 December 23, 2008, update in Cause No. 42061 ECR12 ("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 ECR3, 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 May 13, 2009, update in Cause No. 43114 IGCC2, 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 May 31, 2009, to be $345,309,000. 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. Vincent E. Stroud, Vice President, Regulated Fuels, 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 2009, Gibson, Wabash River, Gallagher and Cayuga Stations are supplied by long-term agreements for more than 90% of their annual requirements. Mr. Stroud stated that Edwardsport is an 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. Stroud 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. Stroud testified that Duke Energy Indiana's average cost of coal per million BTU applicable to its long-term contracts has historically been lower than the cost of the coal the Company would have incurred on the open market. During the twelve month period ended May 31, 2009, coal purchased under long-term commitments comprised approximately 93.26% of total coal receipts. Mr. Stroud 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 over 16 million tons annually. Mr. Stroud 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. Stroud discussed other steps the Company takes to keep coal prices down.

Mr. Stroud also stated that domestic and international coal prices, in general, peaked in the 3rd quarter of 2008 and have fallen significantly over the past nine months. He explained that even though Indiana coal prices never escalated as much as in the Central and Northern Appalachian Basins, such prices also have not fallen as steeply. He explained that there is currently very little market activity in Indiana, due in large part to the weak economic climate that has reduced demand for electricity and resulted in high coal inventories at most utilities, including Duke Energy Indiana. He testified that he expects to see continued volatility in coal prices, but that the high inventory levels should put downward pressure on coal prices, particularly in the spot market. He testified that for the balance of 2009 and 2010, the Company expects coal production to be curtailed across the country in response to the falling demand for coal and high utility inventories. He testified that the Company also expects uncertainty for the demand for coal because of uncertainty with respect to U.S. and world economic conditions. He explained that all of this leads the Company to anticipate continued coal pricing volatility over the next couple of years.

Mr. Stroud explained the Company's coal inventory positions. He testified that as the demand for electricity has been lower than was forecasted for 2009, coal deliveries under long-term contracts have exceeded consumption resulting in significant increases in coal inventories at each of Duke Energy Indiana's coal-fired generating stations. He explained that the reduced electricity demand, low power prices and reduced fuel usage resulting from the current economic recession was exacerbated during July by cool weather in the Midwest. He testified that as a result of the unexpected volume of reduced electricity demand, coal inventory capacity is full or nearly full at each of Duke Energy Indiana's coal-fired generating facilities.

He testified that because of the significant increase in coal inventories, the Company has amended supply contracts to reduce or defer contracted deliveries to prevent or limit the extent to which coal inventories exceed plant storage capacity. He also testified that the Company has recently issued force majeure notices related to the potential impact of the NSR litigation on coal usage. He explained that Duke Energy Indiana has taken steps to cancel or defer over 900,000 tons of coal in 2009 and over 1.2 million tons in 2010. Mr. Stroud further testified that the coal pile at Duke Energy Indiana's Gallagher station is full and the Company is utilizing a third party to store additional coal destined for Gallagher station off-site. In addition, he stated that the Company is implementing or actively exploring coal storage options for coal shipments to other Duke Energy Indiana generating stations. Mr. Stroud 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. Stroud explained that if Duke Energy Indiana were simply to default on its coal purchase obligations, the Company would be exposed to damage claims related to its not taking the contracted deliveries. In addition, Mr. Stroud explained other reasons to avoid default, including avoiding the termination of a contract with a low priced supplier; causing the shut-down of a mine that may be needed for future deliveries; or causing a financially weak supplier to go out of business, which could hurt competition over the long term. He testified that the Company viewed negotiating to buy-out certain coal contracts as a last resort, as this was not as practical as taking steps to control inventories through less drastic means. He explained that given the illiquid nature of the coal market in Indiana, relatively small changes in supply and demand can give rise to significant price volatility. He testified that, as the economy improves and electric demand rises, Duke Energy Indiana's units will consume more coal. He stated that it is in the long-term interest of Duke Energy Indiana and its customers not to take actions that hurt the long-term viability of the regional coal industry.

Ms. Diana L. Douglas, Director, Rates, testified that the Company is following the accounting guidance in the Federal Energy Regulatory Commission ("FERC") Code of Federal Regulations in accounting for coal storage and reclaim costs, such as the costs of the Gallagher station off-site storage. She testified that the Company is including these costs as a cost of the coal, along with other freight, switching, demurrage and transportation costs included in FERC Account 151 and, as such, these costs are eligible for recovery in FAC proceedings. She explained that these costs are added to the cost of inventory at the generating station when the coal that has been stored is ultimately received into the station inventory. She testified that it is the weighted average cost of the station inventory that is used to determine the fuel cost consumed as the coal is burned at the station. She stated further that the fuel cost consumed in serving native load customers is included in the fuel cost amount Duke Energy Indiana presents for approval in its FAC proceedings.

OUCC witness Mr. Gregory T. Guerrettaz noted that the current coal storage facilities at some of Duke Energy Indiana's generating plants are full. In light of this situation and in response to Ms. Douglas's testimony regarding inclusion of coal storage costs in FERC Account 151, Mr. Guerrettaz recommended that the Commission review this issue and offer guidance regarding the appropriate accounting for such costs.

In rebuttal testimony, Ms. Douglas responded to Mr. Guerrettaz's recommendation and also to the Commission's September 9, 2009, docket entry on this same issue. She explained the FERC guidance for Account 151 in the Code of Federal Regulations, the Company's accounting for storage and reclaim costs at temporary interim storage locations and the Company's determination that these types of costs are appropriately accounted for in FERC Account 151. She testified that Duke Energy Indiana interprets FERC Account 151 to mean that all costs incurred while the coal is in transit, and not yet unloaded at the destination generating station at an unloading point where it is available for consumption at the station, should be accumulated as a transportation cost and attached to the cost of the coal for inclusion in Account 151 inventory. Ms. Douglas further testified that Duke Energy Indiana considers storage costs at a temporary interim site between the point of acquisition and the final unloading point to be part of the other transportation costs of the coal, not unlike demurrage costs for coal stored on barges before being unloaded at the final unloading point, and loading and reloading costs at a storage site to be analogous to switching, both of which are specifically identified items for inclusion in Account 151 by the FERC guidance.

She also explained that temporary interim storage locations are frequently used to effect transloading or transfers from one form of transportation to another during transit and to enable coals to be blended before delivery, as well as for temporary storage of excess coal. She stated that key to the Company's interpretation of FERC's guidance is the definition of the "unloading point." The Company interprets "unloading point," not as an interim temporary storage site while the coal is still in transit, but rather as the final unloading point at the generating station, at which time the coal becomes part of the inventory available for consumption purposes at the station.

She explained that until the coal is shipped from an interim storage site to a final unloading point at a generating station, Duke Energy Indiana does not know with certainty which generating station will receive the coal. Interim storage sites may be used to store coal which may be used at multiple stations. She testified that at least as far back as May 2001, Duke Energy Indiana has been incurring these types of costs and including them as transportation costs in Account 151. She testified that this accounting treatment is not new, such storage and reclaim costs have been included in Duke Energy Indiana's costs of fuel, which have been reviewed by the OUCC's auditor and approved by the Commission in previous proceedings, and this treatment is consistent with the accounting used when Duke Energy Indiana's retail electric base rates were last determined and approved by the Commission in Cause No. 42359.

At the hearing, Ms. Douglas confirmed that the Company accounts for interim storage and reclaim costs in FERC Account 151, recording them into the storage location inventory at the time they are incurred. The costs are subsequently transferred and become part of the cost of the operational inventory at the station when the coal is transferred there. The costs become part of the weighted average cost of the station inventory at that time and are expensed as fuel as the coal is consumed. She explained that the storage and reclaim costs may consist of storage fees based on tons stored and loading and unloading fees, depending on the terms of the contract, as well as the incremental transportation costs needed to transport the coal to the operational coal pile at the station. She also confirmed that the Company has incurred storage and reclaim costs and accounted for them in Account 151 since at least May 2001. She explained that such costs have been included in the Gallagher Station inventory and have affected the cost of fuel included in this proceeding, due to transfers of coal made from New Hope Terminal, which is an off-site coal storage location for the Gallagher Station coal, to the station earlier this year.

OUCC witness Mr. Michael D. Eckert testified that the OUCC does not oppose the actions currently being taken by Duke Energy Indiana in response to the Company's rising coal inventory situation. Mr. Eckert did recommend that Duke Energy Indiana provide an update to the Commission on the coal inventory situation in the next FAC proceeding.

Mr. Stroud testified that in his opinion, Duke Energy Indiana is purchasing coal at the lowest cost reasonably possible. Mr. Stroud 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 natural gas purchasing contracts and practices. Mr. Swez described how the price of natural gas has changed over the three-month period from March to May 2009, with the Company experiencing about a 11% decrease in the price of delivered natural gas at its gas burning generation stations during this period. Mr. Swez testified that, in his opinion, Duke Energy Indiana is purchasing natural gas at the lowest cost reasonably possible.

Mr. Stephen M. Herrera, Director, Financial Trading, Bulk Power Marketing and Trading, testified concerning the recent volatility of power and natural gas prices. He explained that starting in April 2005 through the end of May 2009, the average peak daily Midwest ISO CIN Hub real-time LMP was $57.25/MWH. However, there was a wide range of prices during this period, from as low as $18.59/MWH to as high as $188.99/MWH. He also noted significant volatility in natural gas prices.

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 rising coal inventory levels, Duke Energy Indiana shall provide an update on the status of its coal inventories in its FAC 82 proceeding as recommended by the OUCC.

As to the recoverability of coal storage and reclaim costs through the FAC, the Commission finds that a key criteria is whether such costs are properly includable in FERC Account 151. As far back as 1976, the Commission found that Federal Power Commission (now FERC) Account 151 costs constituted fuel which was proper for recovery through FAC proceedings.

> One of the most glaring faults with our existing FACs is the fact that "fuel cost" is not defined. The possibilities for costs to be included within the FAC range from including all costs ancillary to fuel such as, but not limited to, transportation expenses, handling charges, insurance costs, inventory control costs, overhead, etc., to the bare costs for the raw fuel. If the FAC is to serve only the purpose of reflecting changes in fuel costs, and is to maintain any credibility whatsoever with the ratepayers, it should not include any cost not directly applicable to the acquisition of fuel nor should the fuel clause be so narrow as to require construction of fuel procurement contracts between the utilities and their suppliers each time a change in an FAC charge factor is applied for, or discourage utilities from implementing the most efficient and least expensive methods possible for the acquisition and processing of fuel. We find, therefore, that the only costs that should be included in the FAC are those costs allowed by Accounts 151 and 518 for generated and purchased power with identifiable fuel costs of the Commission's Uniform System of Accounts which are, essentially, the same as the Uniform System of Accounts approved by the FPC, and the net energy costs of purchased power without identifiable Accounts 151 and 518 costs. [1]

We find Duke Energy Indiana's analysis that coal storage and reclaim costs are properly includable in Account 151 to be persuasive. Another important consideration is the avoidance of the opportunity for "double recovery" in both base rates and the FAC. Ms. Douglas testified that Duke Energy Indiana has included in Account 151 these types of costs since at least as far back as May 2001 and this was the accounting treatment being used at the time of the Company's last retail electric base rate case in Cause No. 42359. As such, there is no opportunity for double recovery by continuing to allow the recovery of Account 151 costs, including storage and reclaim costs, through the FAC. Accordingly, the Commission finds that Duke Energy Indiana's storage and reclaim costs are properly recoverable through the FAC.

6. Hedging Activities. In his testimony, Mr. Herrera 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. Herrera discussed the results of and the factors influencing the results of the gas hedging for the March through May 2009 reconciliation period. He also stated that the Company had purchased August and September 2009 forward contracts to hedge approximately one-half of its expected burn for July and August 2009 to mitigate price exposure during these periods.

Mr. Herrera 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. Herrera explained that the Company has been making power hedging purchases since January 2006. Mr. Herrera explained that in order to determine the Company's appropriate hedging

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[1] IURC Cause Nos. 33735-S1 and S2, at p. 9 (March 24, 1976); *see also In re: Commission's Investigation*, Cause No. 41363 (IURC, Aug. 18, 1999).

action, Duke Energy Indiana measures the forward purchase price of power against the expected cost of operating Company generation. When this comparison yields an economic advantage from buying forward (*i.e.*, forward purchase price is lower than the expected cost of operating internal generation), the Company utilizes forward power purchase contracts that are financially settled on a specific future date and pays then-current market prices for these products. This action essentially fixes a price for purchased power at a cost lower than the expected cost of operating the Company's own generation for a portion of its expected load. Mr. Herrera 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. Herrera discussed the results of and the factors influencing the results of the power hedging for the March through May 2009 reconciliation period.

Mr. Herrera also explained that, consistent with the Commission's June 25, 2008 Order in Cause No. 38707 FAC68 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 approximately 150 MW of expected load unhedged on a forward forecasted basis.

Mr. Herrera also noted that the Company has met with the OUCC recently to discuss its power hedging practices as required in the power hedging Settlement Agreement and Commission Order approving it, and has provided the OUCC auditor payments as provided for in the Settlement Agreement and Order.

Mr. Herrera stated that the Company has recently instituted one minor modification to its power hedging plans. Due to declining demand and power prices, the Company's forecast would have required it to hedge more than it has historically done. Subsequent to discussions with the OUCC, the Company made a determination to raise its internal risk limit, effectively providing the Company with more flexibility in determining how much to hedge (still leaving at least 150 MW unhedged) in the face of changing economic conditions, and also allowing the Company to be more consistent with its historic power hedging amounts when warranted.

Mr. Herrera 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. Douglas explained that the amount included in fuel costs for hedging activity in this proceeding was a realized net gain of $1,796 for gas hedging activity and a realized net loss of $836,412 for power hedging activity (exclusive of Midwest ISO virtual activity).

OUCC witness Mr. Eckert testified 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 FAC68 S1. He also stated that the OUCC has begun issuing data requests on this issue and expects to file testimony in the Company's next FAC.

The Commission's Order in Cause No. 38707 FAC67, dated April 6, 2006, found gas hedging activities to be reasonable. The Company has included a positive gas hedging value of $1,796 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 FAC68 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. Under the Settlement terms, the parties agreed that all cost recovery issues through February 29, 2008, were resolved and that any power hedging activities entered into by Duke Energy Indiana from November 30, 2007, through July 31, 2008, would not be challenged on the basis that Duke Energy Indiana utilized a flat hedging methodology. However, such hedging activities entered into during that time period could be challenged on the basis of other prudence criteria. No party has expressed concerns regarding the realized net loss 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 loss. 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 $836,412 of realized power hedging losses in the calculation of fuel costs in this proceeding.

7. **Orders in Cause Nos. 42685, 38707 FAC70, 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 Independent Transmission System Operator, Inc. ("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 ASM market, as authorized by the Commission in Cause No. 38707 FAC77 and Cause No. 38707 FAC80.

The Commission Order in Cause No. 38707 FAC70, dated December 28, 2006, subsequently amended the June 1 Order regarding uninstructed deviation ("UD") amounts. In that Order the Commission found UD penalties incurred on or after June 1, 2006 are a reasonable cost of generating power in the Midwest ISO market and may be properly included as a cost of fuel in FAC proceedings, unless it is demonstrated that the utility failed to use good utility operating practice. The Commission further found that the Company should credit customers with UD revenues in future FAC proceedings and cease doing so in Rider 68. The Commission also required an explanation in support of cost recovery for any given month in which UD charges exceeded such revenues.

Ms. Douglas explained in her direct testimony that, effective with the January 6, 2009, implementation of the ASM, the Midwest ISO discontinued assessing UD charges or crediting generators with UD revenues. Ms. Douglas testified in her direct testimony that no new UD charges and revenues were included by the Company for the months of March through May 2009, although some small adjustments to the amounts initially included in the December 2008 and January 2009 fuel costs presented in Cause No. 38707 FAC80 have been included in the Company's prior period adjustments due to routine Midwest ISO resettlements for those months. She observed that for future FAC filings, should there be any adjustments to UD amounts included in previous FAC filings due to additional Midwest ISO resettlements for periods up through January 2009, the Company will include such adjustments with other prior period adjustments.

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. Ms. Douglas explained that these costs and credits had been included in the fuel costs being requested for recovery in this proceeding for the reconciliation months of March, April and May 2009, as well as including the applicable amounts for January and February 2009 as prior period adjustments. Ms. Douglas also explained that as a result of the Phase II Order, the Company was ordered to discontinue reflecting Day Ahead RSG Distribution Amounts and Real Time RSG First Pass Distribution Amounts in its cost recovery proceedings pursuant to its Standard Contract Rider No. 68 ("RTO Tracker") and to begin reflecting these charge types in the cost of fuel in future FAC proceedings. Ms. Douglas testified that the Company is implementing the transfer of reporting and cost recovery for the Day Ahead RSG Distribution Amounts and Real Time RSG First Pass Distribution Amounts in this proceeding, beginning with the March 2009 fuel costs, which is the first reconciliation period reflected in this FAC proceeding. She explained that the Company plans to include any adjustments required due to future Midwest ISO resettlements for these two charge types related to periods prior to March 2009 in the Rider 68 tracker rather than the FAC proceedings. She further explained that this implementation approach was discussed with representatives from the OUCC.

Mr. Scott A. Burnside 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)	Jan 09	Feb 09	Mar 09	Apr 09	May 09
Regulation Cost Dist	0.1935	0.1179	0.1187	0.1073	0.0991
Spinning Cost Dist	0.1149	0.0728	0.0422	0.0536	0.0436
Supplemental Cost Dist	0.0042	0.0040	0.0042	0.0045	0.0046

Ms. Douglas also testified that Duke Energy Indiana is asking the Commission to authorize it to include in this and its future FAC proceedings the recovery of net credits for the Midwest ISO's Contingency Reserve Deployment Failure Charge Uplift Amount ("Uplift Amount"), which is associated with the ASM. Ms. Douglas explained that this Uplift Amount is a separately identified component of the Midwest ISO's Revenue Neutrality Uplift Amount ("RNU"). Funds collected by the Midwest ISO from its charges to Generators for the Contingency Reserve Deployment Failure Charge Amount, which is one of the listed charges that the Commission approved as a cost of fuel in its Phase II Order, are credited to Asset Owners via this Uplift Amount. The Phase II Order did not specifically authorize the inclusion of the Uplift Amount by detailing it in the list of charges to be included as fuel in FAC proceedings on pages 39 and 40 of the Order. However, the Phase II Order provides that RNU should continue to be treated for ratemaking purposes as it had been treated previously by the Joint Petitioners, "and as described in their testimony in this proceeding." *Id.* at pp. 40-41.

Ms. Douglas explained that all Joint Petitioners testified in Phase II of Cause No. 43426 that if the Midwest ISO separately identified the Uplift Amount subcomponent of RNU, it should be included as an offset to fuel cost and flowed through to customers in their respective FAC proceedings. Ms. Douglas also testified that the inclusion of the Uplift Amount in fuel is consistent with the Commission's previous order in Cause No. 38707 FAC70 regarding a similar uplift credit for Uninstructed Deviation Revenues, for which the corresponding charge was also approved to be included as a cost of fuel. Ms. Douglas explained that by including the Uplift Amount as a cost of fuel or offset to the cost of fuel in FAC proceedings it will ensure that customers of all Joint Petitioners in Cause No. 43426 receive consistent and timely benefit of the credits. In addition, Ms. Douglas noted that personnel from the Company and the other Joint Petitioners in Cause No. 43426 met with representatives of the OUCC and the Indiana Industrial Group as part of an ongoing dialog regarding the ASM, as ordered by the Commission in its Phase II Order.

Ms. Douglas also testified that Duke Energy Indiana is requesting that the Commission remove the "subject to" stipulation with regard to ASM charges and credits which was contained in the Order in Cause No. 38707 FAC80 now that the Company has implemented the Phase II Order in its fuel cost calculations in this proceeding.

OUCC witness Mr. Eckert testified that Applicant's proposed ratemaking treatment for the new ASM Charge types follows the treatment ordered by the Commission in its Phase II Order.

He also noted that Applicant has reported the average monthly distribution costs of Regulation, Spinning, and Supplemental Reserves charge types in accordance with the Phase II Order. He also recommended the Commission allow Applicant to recover its UD charges. With regard to the Day Ahead RSG Distribution Amounts and Real Time RSG First Pass Distribution Amounts charge types being moved from Rider 68 to the FAC proceedings, Mr. Eckert testified that that the OUCC does not oppose the implementation approach taken by Duke Energy Indiana.

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. We further find that Duke Energy Indiana is authorized to include credits or charges for Contingency Reserve Deployment Failure Charge Uplift Amounts in this and future FAC proceedings. In addition, because the Company has implemented our Phase II Order from Cause No. 43426 in its fuel cost calculations in this proceeding, including the impacts of the Order on the costs presented in FAC 80 for January and February 2009, the Commission's Order in Cause No. 38707 FAC 80 approving the inclusion of ASM charges and credits is made final with respect to those charges and credits.

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 described Duke Energy Indiana's participation in the energy markets and testified that it was consistent with the testimony presented in Cause No. 42685.

In the Phase I Order, the Commission approved certain changes in the operations of Duke Energy Indiana as a result of the implementation of the ASM. Specifically, we found that Duke Energy Indiana (and the other electric utilities participating in Cause No. 43426) "are authorized to transfer additional balancing authority functions in accordance with the Amended Balancing Authority Agreement and implement the operational changes necessary to permit Joint Petitioners to participate in the Midwest ISO's ASM." *Id.* at p. 23. Mr. Swez explained 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. He also described the Company's experience thus far under ASM. Mr. Swez explained that to his knowledge the ASM has 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, as a result of Duke Energy Indiana's current coal inventory capacity levels at its coal-fired generating facilities, the Company intends to offer specific coal units to the Midwest ISO on a must-run basis more frequently than usual for purposes of meeting the Company's forecasted native load. He stated that typically this practice would only affect coal units that might be cycled off-line on weekends, but it could also affect certain marginal units on weekdays. He explained that this offer protocol is consistent with how Duke Energy Indiana's generating units have generally been offered in the past. He testified that it has only been in recent months that the Company began offering some marginal units with a status of "economic" for very low priced weekends and weekdays. Mr. Swez testified that this dispatch protocol would be subject to applicable operating constraints affecting each unit, such as start-up and shut-down limitations and the operating limitations applicable to the Wabash River 2, 3 and 5, and Gallagher 1 and 3 units related to the NSR litigation.

Mr. Swez testified that due to high coal inventory levels at Duke Energy Indiana's Gallagher Generating Station and the use of off-site coal storage, as explained by Mr. Stroud, on March 15, 2009, Duke Energy Indiana started incorporating avoided costs related to off-site coal storage into the dispatch and commitment costs of all units at Gallagher Station. He explained that this was done to reflect the correct unit economics of avoided off-site coal storage costs. He stated that the dispatch and commitment costs of each unit were reduced for purposes of Duke Energy Indiana's offers of these units to the Midwest ISO by the off-site coal storage costs that could be avoided if the unit would be cleared for dispatch by the Midwest ISO. Mr. Swez testified that, given off-site coal storage and reclaim costs are recovered as a part of fuel costs in FAC proceedings when the coal being stored is ultimately burned, Duke Energy Indiana believes it makes sense to try to avoid some of these storage costs by offering the units with the storage costs subtracted from the other unit operating costs. He testified that to the extent the units are dispatched, coal coming to Gallagher Station is consumed and off-site storage costs are avoided, Duke Energy Indiana's customers ultimately benefit. He further stated that once the need for the off-site coal storage is eliminated, this change to the Gallagher Unit dispatch and commitment costs for purposes of offering the units to the Midwest ISO will be removed.

Mr. Swez testified that the Company would implement similar changes in its dispatch and commitment costs for other coal-fired units to reflect new storage facilities. He further explained that 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. Reducing the dispatch and commitment costs of units by the amount of incremental coal storage costs so as to dispatch such units more frequently is one way to try to reduce such storage costs. Mr. Swez stated that as an example, the Company planned to institute this approach related to a temporary coal storage facility at Gibson Station.

As noted previously, OUCC witness Mr. Eckert testified that the OUCC does not oppose the actions currently being taken by Duke Energy Indiana in response to the Company's rising coal inventory situation.

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. Further, we find the Company's bidding of its units, specifically the taking into account of incremental storage costs, is a reasonable response to the Company's rising inventory levels, is consistent with economic dispatch and is in the best interests of customers. Additionally, we appreciate the potential need to bid units as "must-run," but also recognize that the associated dispatch results, should such bidding strategy alter the native/non-native load assignment of such units, may be subject to further prudence review.

9. <u>New Source Review ("NSR") Impacts on Operations</u>. Ms. Diane L. Jenner, Director, Regulatory Strategy, provided testimony about the NSR lawsuit brought against Duke Energy Indiana in the U.S. District Court for the Southern District of Indiana, the outcome of the May 2008 jury trial, the subsequent remedy phase of the trial, and the May 29, 2009 ruling. She explained that in addition to the Court ordering the shutdown of Wabash River Units 2, 3, and 5 by September 30, 2009, the Judge ordered Duke Energy Indiana to run Wabash River Units 2, 3, and 5 at a rate not to exceed the pre-project baseline emissions until the time the units are shut down (unless the Company can show the Court good cause for running those units above the baseline). In addition, she stated that the Court ordered Duke Energy Indiana to permanently surrender SO_2 emission allowances (equal to the SO_2 emissions from Wabash River Units 2, 3, and 5) for the period May 22, 2008, through shut down of the units on September 30, 2009. Ms. Jenner testified that Duke Energy Indiana filed post-trial motions with the trial court asking the Judge to enter judgment in its favor based on erroneous pre-trial rulings, but the judge denied the motions. She advised that Duke Energy Indiana is currently evaluating its appeal options at the Seventh Circuit Federal Court of Appeals. Ms. Jenner also testified that the Midwest ISO is performing an Attachment Y study, which will assess the reliability impacts of shutting down these units. She reported that Duke Energy Indiana expects to receive the results of this study during August and, depending on the outcome, will further consider its options.

Consistent with the Commission's Order in Cause No. 38707 FAC80, Mr. Swez and Ms. Jenner testified regarding the potential impact of the shutdown of these units on future fuel costs and capacity requirements. Mr. Swez testified that these units are relatively low cost units and, to the extent that electric demand must be satisfied with higher cost units once the Wabash River units are shut down, fuel costs may be expected to go up. He explained that many variables come into play as to the actual cost impact, including changes in demand, Midwest ISO LMPs, and the availability of other Duke Energy Indiana generating facilities.

Ms. Jenner testified about the impact the September 30, 2009 shut down will have on the capacity requirements of Duke Energy Indiana going forward. She testified that, even prior to the Court's order, Duke Energy Indiana was expected to be short of on-system capacity to meet the Midwest ISO Resource Adequacy Requirements for the summers of 2010 and 2011 until the Edwardsport IGCC goes in service in June 2012. She testified that without the 265 MW ICAP / 246.4 MW UCAP capacity from Wabash River 2, 3, and 5, Duke Energy Indiana will need to make additional short-term purchases to be in compliance for Planning Years 2010/11 and 2011/12. She testified that Duke Energy Indiana will have sufficient capacity to comply with the Midwest ISO's requirements for the remainder of Planning Year 2009/10 (*i.e.,* through May 2010).

Ms. Jenner testified that the estimated additional Planning Resource Credit ("PRC") purchases that are expected to be required if the Wabash River units are shutdown on September 30, 2009, as well as the total forecasted PRC purchases required for the next few years, are as follows:

	Additional PRC Purchases	Total PRC Purchases
June 2010	79.5	79.5
July 2010	246.4	424.4
August 2010	246.4	426.5
January 2011	34.1	34.1
June 2011	236.1	236.1
July 2011	246.4	591.2
August 2011	246.4	588.1
September 2011	42.7	42.7
January 2012	54.2	54.2
July 2012	16.4	16.4
August 2012	19.7	19.7

She explained that these amounts were based on the assumption that the Midwest ISO's Planning Reserve Margin ("PRM") for future Planning Years would be the same as it is for Planning Year 2009/10 (*i.e.,* 5.35% on a UCAP basis). She testified that the number of PRCs actually required will depend on a number of factors, including the load forecast, the amount of Energy Efficiency and Demand Response on Duke Energy Indiana's system, the number of UCAP MW the Company is assigned for its existing capacity, and the actual PRM required in future years based on the Midwest ISO's Loss of Load Expectation studies, among other assumptions.

Mr. Swez also testified that in the liability phase of the May 2009 NSR lawsuit the jury found against the Company with regard to projects performed on Gallagher Units 1 and 3 and the remedy trial is set for January 25, 2010. He explained that currently Duke Energy Indiana is voluntarily operating these units under pre-project NSR baseline levels for 2009 in order to limit annual emissions, but did not anticipate this operation limitation would have any effect on these units' generation dispatch and commitment in 2009 on an annual basis.

OUCC witness Mr. Eckert testified that the Company's witness Ms. Jenner provided testimony regarding the status of NSR related to Wabash River Station Units 2, 3 and 5 and also the potential impacts of the District Court's ruling as recommended by the OUCC in the FAC80 proceeding. Mr. Eckert recommended that in its next FAC proceeding Duke Energy Indiana update the Commission on (1) how the shutdown of Wabash River Units 2, 3 and 5 will impact the Company's ability to meet future summer peak demands; (2) how Duke intends to meet those future summer peak demands; and (3) Seventh Circuit Federal Court of Appeals option. With regards to Gallagher Units 1 and 3, Mr. Eckert also recommended that Duke Energy Indiana should provide information in its next FAC filing for (1) how the potential shutdown of Gallagher Units 1 and 3 will impact the Company's ability to meet future summer peak demands; and (2) how Duke Energy Indiana intends to meet those future summer peak demands if Gallagher Units 1 and 3 are shut down.

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 May 31, 2009. Duke Energy Indiana's authorized jurisdictional operating expenses (excluding fuel costs) are $788,939,000. For the 12-month period ended May 31, 2009, Duke Energy Indiana's jurisdictional operating expenses (excluding fuel costs) totaled $1,029,686,000. 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 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.

The fuel cost charge test period used for earnings test computations in this Cause was the 12 months ended May 31, 2009. During this period, Duke Energy Indiana's actual jurisdictional electric operating income level was $207,611,000, while its authorized phased-in jurisdictional electric operating income level for purposes of Indiana Code § 8-1-2-42(d)(3), was $345,309,000. Therefore, the Commission finds that Duke Energy Indiana did not earn a return in excess of its authorized level during the 12 months ended May 31, 2009.

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 October through December 2009 will be $65,110,333 or $0.025238 per kWh. Duke Energy Indiana previously made the following estimates of its fuel costs for the period March through May 2009, 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
March 2009	24.503	25.918	(5.46)
April 2009	24.727	24.724	0.01
May 2009	22.519	25.739	(12.51)
Weighted Average	23.918	25.480	(6.13)

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 (6.13)%. 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 October through December 2009 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 FAC45, 38708 FAC45, 38707 FAC56, and 38707 FAC59. The benchmarks are as follows:

Month / Year	Benchmark $/MWh 1/	Facility
March 2009	114.44	Connersville 1
April 2009	149.12	Connersville 1
May 2009	143.67	Connersville 1

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 March through May 2009 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 October through December 2009 billing cycles is computed as follows:

	$ / kWh
Projected Average Fuel Cost	0.025238
Net Variance	(0.001755)
Adjusted Fuel Cost Factor	0.023483
Less: Base Cost of Fuel	0.014484
Fuel Cost Adjustment Before Applicable Taxes	0.008999
Adjustment for Utility Receipts Tax	0.000137
Fuel Cost Adjustment Factor Adjusted for Applicable Taxes	0.009136

The net variance factor shown above reflects $11,285,236 of over-billed fuel costs applicable to retail customers that occurred during the period March through May 2009. Coal, gas, and power price trends affecting fuel costs were discussed in the testimonies of Mr. Swez, Mr. Herrera and Mr. Stroud, as outlined in Findings Nos. 5 and 6 above.

OUCC witness Mr. Gregory Guerretaz 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 May 31, 2009, 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.

On June 25, 2008, the Commission issued its Order in Cause No. 38707 FAC76 which, among other matters, authorized a sub-docket in that proceeding to further examine whether the Gibson Unit 4 outage earlier that year resulted from imprudent maintenance by the Company. Recognizing that the variance amounts presented above may be altered by the outcome of that proceeding, we find, subject to the outcome of the sub-docket established in cause No. 38707 FAC 76 S1, the amounts presented above were calculated appropriately.

16. Effect on Residential Customers. The approved factor represents a decrease of $0.003768 per kWh from the factor approved in Cause No. 38707 FAC80. The typical residential customer using 1,000 kWhs per month will experience a decrease of $3.76, or 4.3%, on his or her base electric bill compared to the factor approved in Cause No. 38707 FAC80 (excluding various tracking mechanisms and sales tax).

17. Fuel Adjustment for Steam Service. On December 30, 1992, the Commission issued its Order in Cause No. 39483 approving the June 18, 1992 Agreement between Duke Energy Indiana and Premier, which included a change in the method used to calculate Premier's fuel cost adjustment as well as an update to the base cost of fuel. The fuel cost adjustment factor for Premier of $1.0751815 per 1,000 pounds of steam was calculated on Exhibit B, Schedule 1, of the Verified Application; this factor will be effective for the October through December 2009 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 Premier that resulted in a $89,854 payable to Premier for the months of March through May 2009.

The Commission finds that Duke Energy Indiana's proposed change in the fuel cost adjustment factor for Premier of $1.0751815 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 $89,854 payable to Premier has been properly determined and should be approved.

18. Shared Return Revenue Credit Adjustment for Premier. Per the June 18, 1992 Settlement Agreement, Premier 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 May 2009. Therefore, we find Premier 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 is authorized to include credits or charges for Contingency Reserve Deployment Failure Charge Uplift Amounts as a cost of fuel in this and future FAC proceedings, as described in Finding No. 7 of this Order.

4. 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 October 2009, 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.

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

HARDY, ATTERHOLT, GOLC, AND ZIEGNER CONCUR; LANDIS ABSENT:

APPROVED: SEP 23 2009

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