STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY FOR APPROVAL OF A FUEL COST CHARGE AND CUSTOMER CREDIT ADJUSTMENT TO BE APPLICABLE DURING THE BILLING MONTHS OF FEBRUARY, MARCH AND APRIL 2012, PURSUANT TO IND. CODE § 8-1-2-42 AND CAUSE NO. 41746 AND FOR APPROVAL OF RATEMAKING TREATMENT FOR THE COST OF WIND POWER PURCHASES PURSUANT TO CAUSE NO. 43393.	)	CAUSE NO. 38706 FAC 93 APPROVED: JAN 25 2012

ORDER OF THE COMMISSION

Presiding Officers:
Kari A.E. Bennett, Commissioner
Angela Rapp Weber, Administrative Law Judge

On November 2, 2011, Northern Indiana Public Service Company ("NIPSCO" or "Petitioner") filed its petition with the Indiana Regulatory Commission ("Commission") for approval of a fuel cost adjustment and customer credit adjustment to be applicable for bills rendered by Petitioner during the billing months of February, March, and April 2012. Petitioner prefiled its direct testimony and exhibits in support of its petition on November 4, 2011. The NIPSCO Industrial Group ("NIPSCO-IG") filed its Petition to Intervene on November 10, 2011, which was granted by the Presiding Officers in a Docket Entry dated November 28, 2011. On December 7, 2011 the Indiana Office of Utility Consumer Counselor ("OUCC") filed its report in this Cause along with its supporting direct testimony. On December 28, 2011, Petitioner filed revised exhibits as a result of the Commission's December 21, 2011 Order in Cause No. 43969.

Pursuant to public notice duly given and published as required by law, proof of which was incorporated into the record by reference and placed in the Commission's official file, a public hearing in this Cause was held on January 4, 2012 at 10:00 a.m. in Room 224, 101 W. Washington Street, Indianapolis, Indiana. At the hearing Petitioner, the OUCC, and the NIPSCO-IG appeared by counsel. Petitioner and OUCC offered their respective prefiled testimony and exhibits, which were admitted into evidence without objection. No other party or members of the general public appeared.

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

1. **Commission Jurisdiction and Notice.** Proper notice of the hearing in this Cause was given as required by law. Petitioner is a public utility corporation incorporated under the laws of the State of Indiana, operating electric utility properties in northern Indiana and is subject to the jurisdiction of this Commission as provided in the Public Service Commission Act, as amended, Indiana Code ch. 8-1-2. Thus, the Commission has jurisdiction over NIPSCO and the subject matter of this Cause.

2. **Petitioner's Characteristics.** Petitioner has its principal office at 801 East 86th Avenue, Merrillville, Indiana. Petitioner is engaged in rendering electric public utility service in the State of Indiana and owns, operates, manages and controls, among other things, plants and equipment within the State of Indiana used for the production, transmission, delivery and furnishing of such service to the public.

3. **Available Data on Actual Fuel Costs.** The Petitioner's cost of fuel to generate electricity and the cost of fuel included in the cost of purchased electricity at the time this Cause was initiated were approved July 15, 1987 in Cause No. 38045. On December 21, 2011, the Commission approved a base rate Order for Petitioner in Cause No. 43969 ("43969 Order"). Petitioner's cost of fuel to generate electricity and the cost of fuel included in the cost of purchased electricity approved in that proceeding was $0.028729 per kWh (Petitioner's Exhibit B, Revised Schedule 1, p. 1, Ln. 30). Petitioner's cost of fuel to generate electricity and the cost of fuel included in the cost of purchased electricity for the months of July, August, and September 2011 averaged $0.031747 per kWh (Petitioner's Exhibit B, Schedule 5, p. 4, Ln. 28).

4. **Requested Fuel Cost Charge.** Petitioner seeks to change its fuel cost adjustment charge from the current charge of $0.003075 per kWh (Petitioner's Revised Exhibit 1-C, Ln. 8) to a charge of $0.004919 per kWh (Petitioner's Exhibit B, Revised Schedule 1, p. 1, Ln. 32) for all bills rendered in February, March, and April, 2012 billing months. The requested fuel cost adjustment charge includes a variance of $3,942,423 (Petitioner's Exhibit B, Revised Schedule 1, p. 1, Ln. 26d) that was under-collected during July, August, and September 2011. Petitioner's estimated monthly average cost of fuel to be recovered in this proceeding for the period January, February, and March 2012 is $43,832,278 (Petitioner's Exhibit B, Revised Schedule 1, p.1, Ln. 24), and its estimated monthly average sales for that period are 1,344,718 MWh (Petitioner's Exhibit B, Revised Schedule 1, p. 1, Ln. 11).

5. **Statutory Requirements.** Ind. Code § 8-1-2-42(d) states that this Commission shall grant a fuel cost adjustment charge if it finds that:

> (1) The electric utility has made every reasonable effort to acquire fuel and generate or purchase power or both so as to provide electricity to its retail customers at the lowest fuel cost reasonably possible;
>
> (2) The actual increases in fuel cost through the latest month for which actual fuel costs are available since the last order of the Commission approving basic rates and charges of the electric utility have not been offset by actual decreases in other operating expenses;
>
> (3) The fuel adjustment charge applied for will not result in the electric utility earning a return in excess of the return authorized by the Commission in the last proceeding in which the basic rates and charges of the electric utility were approved. However, subject to Ind. Code § 8-1-2-42.3, if the fuel charge applied for will result in the electric utility earning a return in excess of the return authorized by the Commission in the last proceeding in which basic rates and charges of the electric utility were approved, the fuel charge applied for will be reduced to the point where no such excess of return will be earned.

(4) The utility's estimates of its prospective fuel costs for each such three (3) calendar months are reasonable after taking into considerations: (A) the actual fuel costs experienced by the utility during the latest three (3) calendar months for which actual fuel costs are available; and (B) the estimated fuel costs for the same latest three (3) calendar months for which actual fuel costs are available.

6. **Fuel Costs and Operating Expenses.** Petitioner's Exhibit 2-A, page 1, Line 22 shows that fuel costs for the twelve months ending September 30, 2011, increased $245,214,122 from the pro forma level established in Cause No. 38045, Petitioner's last base rate case in which new basic rates and charges were approved prior to the period reconciled in this Cause. Petitioner's Exhibit 2-A, Line 24 also shows that Petitioner's total operating expenses, excluding fuel in the twelve months ending September 30, 2011, increased by $293,287,671 from the pro forma level established in Cause No. 38045. The Commission finds that Petitioner's fuel costs have increased since its applicable general rate Order, and the actual increases in fuel costs have not been offset by actual decreases in other operating expenses.

7. **Efforts to Acquire Fuel and Generate or Purchase Power to Provide Electricity at the Lowest Reasonable Cost.** Petitioner's witness Kevin A. Strnatka testified that NIPSCO made every reasonable effort to acquire fuel so as to provide electricity to its retail customers at the lowest fuel cost reasonably possible. He testified that Petitioner's primary fuel for generation of electric energy is coal (86.32% for the three months ended September 30, 2011).

With respect to NIPSCO's coal procurement process, Mr. Strnatka testified that NIPSCO considers several factors in purchasing coal, including the delivered price, the coal quality that is best suited for a particular generating unit, the sulfur content, and the economic and technical suitability of certain low cost fuels to be blended at our generating units to maintain the lowest, reasonably possible "as-burned" fuel cost. Mr. Strnatka testified that NIPSCO also considers the availability, reliability and diversity of particular coal suppliers and coal transporters in its fuel procurement practices. He stated that NIPSCO currently has five long term contracts with four coal producers and that NIPSCO would meet any remaining coal requirements through spot purchases. Mr. Strnatka explained that NIPSCO competitively bids all coal purchased under a long term agreement. He stated NIPSCO prepares a preliminary evaluation sheet incorporating all of the bidder information such as mine origin, Btu, sulfur, ash, available tons per year and price on both a per ton and $ per million Btu basis. He testified that the final evaluation sheet, in addition to the cost of coal, includes the transportation cost for each of the proposals and any adjustments required to place all bids on an equivalent basis. Mr. Strnatka stated that NIPSCO negotiates price and commercial terms and conditions with the low evaluated bidder(s).

Mr. Strnatka testified that due to volatility in the coal markets, producers and customers are reluctant to execute fixed price long term contracts without some type of market price adjustment mechanism and that maintaining a market price balance is beneficial to both parties. He explained that two of NIPSCO's long term contracts have firm prices but the firm prices increase each year of the contract to a price set out in the contract. Two of NIPSCO's long term contracts have prices that are adjusted annually based on the average prices during the prior year and then remain firm throughout that year. One of NIPSCO's long term contracts has semi-annual price adjustments that are based on changes in published government indices.

Mr. Strnatka testified that before NIPSCO agrees to a coal price increase based on contract provisions, NIPSCO's Fuel Supply Department, which is responsible for administering all coal contracts, verifies that only contract-allowable changes are made to the mine and transportation prices. He explained that after a price adjustment is received, NIPSCO requests supporting evidence in the form of actual invoices and records, as well as published government data, to justify the price adjustment. Mr. Strnatka testified that no price adjustments are made until NIPSCO is satisfied that the charges are in accordance with the contract, and are justified by actual costs or changes in cost indices.

Mr. Strnatka testified that the delivered cost of coal for NIPSCO for the twelve months ending September 30, 2011 was $50.68 per ton or $2.522 per million Btu. The delivered coal cost for the reconciliation period (July, August, and September 2011) was $51.73 per ton or $2.579 per million Btu. Mr. Strnatka stated NIPSCO made four spot purchases of high sulfur coal, three spot purchases for its Bailly Generating Station, one spot purchase for Units 17 and 18 at the R.M. Schahfer Generation Station, and four spot purchases of Powder River Basin ("PRB") coal for its units that burn PRB coal during the reconciliation period. He testified the average market spot price of coal (excluding transportation costs) during the reconciliation period was $14.25 per ton for PRB coal, $51.56 for Illinois Basin high sulfur coal, and $76.14 per ton for Pittsburgh #8 coal.

With respect to the market factors affecting the supply, demand, and cost of coal during the reconciliation period, Mr. Strnatka testified that coal supply during the reconciliation period was impacted by the global demand for domestic coal from all coal producing regions in the United States, the flooding in the Plains creating transportation issues for PRB coal, and the excessive heat during the summer months, particularly in the southwest region of the country. He noted competitive natural gas pricing and a stagnant economy tempered the demand for coal and, with the exception of Pittsburg #8 coal, PRB and high sulfur coal remained relatively flat during the reconciliation period. Mr. Strnatka testified NIPSCO's delivered cost of coal during the reconciliation period decreased slightly compared to the second quarter of 2011 from $52.14 per ton or $2.601 per million Btu to $51.73 per ton or $2.579 per million Btu, which can be attributed to an increase in PRB deliveries during the reconciliation period and more attractive spot pricing for PRB coal.

Based on the testimony presented, we find that NIPSCO has adequately explained its coal procurement decision making and we find that its acquisition process is reasonable. Mr. Strnatka's testimony demonstrates NIPSCO has a diverse group of long-term coal contracts with different types of price adjustment mechanisms. Mr. Strnatka explained why NIPSCO and its coal suppliers are reluctant to execute fixed price long term contracts without some type of market price adjustment mechanism and that maintaining a market price balance is beneficial to both parties. Mr. Strnatka also explained in testimony how NIPSCO makes procurement decisions and the type of market data that NIPSCO tracks and reviews. The Commission notes NIPSCO has recently begun to provide more information to intervenors regarding its coal procurement practices. Accordingly, we find NIPSCO has adequately demonstrated that its coal procurement policies are reasonable and prudent.

NIPSCO witness Roger A. Huhn stated NIPSCO purchases natural gas on a spot basis because natural gas is not used as a baseload fuel. Therefore, it is purchased on an intermittent basis when one of NIPSCO's gas-fired generation units is more economical to run or needs to run for operational purposes. Mr. Huhn testified NIPSCO has made every reasonable effort to purchase natural gas so as to provide electricity to customers at the lowest reasonable price.

With respect to NIPSCO's efforts to maximize the value of Renewable Energy Credits ("RECs") for its customers, Mr. Williamson stated Indiana does not currently have regulations that guide the certification and accounting for RECs so NIPSCO has held the RECs on account with the Midwest Renewable Tracking System due to their relatively low market value and in the event that the State of Indiana were to approve a renewable energy standard. He noted the Indiana General Assembly recently passed Senate Bill 251, which includes a voluntary renewable energy standard, and NIPSCO will monitor the results of that legislation and make appropriate changes, if required, in the way RECs are utilized. He testified NIPSCO's treatment of RECs has not changed since FAC92.

The Commission finds NIPSCO should continue to include in its quarterly FAC filings updates concerning its utilization of RECs associated with wind purchases being recovered through the authority granted in Cause No. 43393 and any other future renewable purchases. Also, based on the evidence further discussed in this Order, we find Petitioner has made every reasonable effort to acquire fuel and generate or purchase power so as to provide electricity to its retail customers at the lowest fuel cost reasonably possible.

8. <u>Midwest ISO Day 2 Energy Costs</u>. NIPSCO took into account in its forecast for this case the operational changes associated with the Midwest Independent System Operator ("Midwest ISO") Day 2 energy market, in accordance with the Commission's Orders in Cause Nos. 42685, 43426, 43665 and its FAC proceeding from FAC 68. Petitioner included in the FAC factor $7,207,166 as the total "MISO Components of Fuel Cost" for the months of July, August, and September 2011. (Petitioner's Exhibit B, Schedule 5, p. 4, Ln. 19).

9. <u>Estimation of Fuel Cost</u>. Petitioner estimated that its prospective total average fuel costs for the billing months of February, March, and April 2012 will be $43,832,278 (Petitioner's Exhibit B, Revised Schedule 1, Ln. 24) on a monthly basis.

Mr. Strnatka testified NIPSCO anticipates that its delivered coal cost during the forecast period of January, February, and March 2012 will be approximately $53.00 per ton, or $2.61 per million BTU. Mr. Strnatka explained that one PRB contract will expire at the end of 2011 and is currently being bid for a multi-year term. He stated potential increased incremental demand for PRB coal due to the Cross-State Air Pollution Rule ("CSAPR") could elevate demand for this ultra-low-sulfur coal and drive prices up, but uncontrolled coal fired plants could shut down, reducing coal demand. He noted NIPSCO is currently negotiating a price reopener with a high-sulfur coal producer for 2012 with the expected price to be less than the current coal price in 2011, and a new transportation agreement is currently being evaluated for deliveries of both PRB and high-sulfur coal. Mr. Strnatka stated transportation rates for PRB and part of NIPSCO's high-sulfur coal requirements are projected to be slightly less than current rates in 2011 and that overall, NIPSCO is projecting a delivered coal cost of $2.60 per million Btu for 2011 with a slight increase to $2.61 per million Btu for the first quarter of 2012. He testified the projected delivered cost of $2.61 per million Btu in the first quarter of 2012 could be influenced by the volatility in the diesel fuel market. Mr. Strnatka testified the average spot market prices for calendar year 2012 (which do not include cost of transportation) are currently $15.53 per ton for PRB coal, $47.85 per ton for Illinois Basin coal, and $77.73 per ton for Pittsburgh #8 coal.

Mr. Strnatka explained NIPSCO incorporates all current coal contract prices, estimates of any coal contract price adjustments that might be warranted, transportation contract prices, an assessment of the pricing impact of fuel surcharges on the delivered cost based on current price of crude oil, and an evaluation of the spot market price of coal in developing the estimate for the forecast period. These inputs are provided to NIPSCO's Generation Dispatch & Marketing Group to be used in quarterly updates of PROMOD, its cost production modeling system, to develop costs based on demand and projected load forecasts.

With respect to the factors NISPCO believes will impact the supply, demand, and cost of coal during the forecast period, Mr. Strnatka cited the price of natural gas, weather, continued strong international demand for domestic coal, high demand for PRB coal, due to CSAPR and lower electrical demand, which is the result of a stagnant economy. He testified that overall, these factors could offset each other, with the potential of a slight increase in coal pricing during the forecast period. He explained that the main factor impacting the delivered cost of coal is the volatility of diesel fuel. He testified that at one time the cost of crude was over $115 per barrel but that the current cost of crude ranges from $80 to $95 per barrel. Mr. Strnatka testified that if the price of crude remains in this range, NIPSCO's delivered coal cost will not be influenced by excessive fuel surcharges paid to the railroads.

In our FAC 90 Order (at 6), we ordered NIPSCO to provide detailed testimony and information regarding: (1) average spot market price of coal; (2) factors affecting the supply, demand, and cost of coal; (3) any known factors that significantly impact or affect the supply, demand, and cost of coal during the forecast and reconciliation periods; (4) any known factors that significantly impact the delivered cost of coal during the forecast and reconciliation period; and (5) the process NIPSCO utilizes to procure contracted coal supplies. We find that in this proceeding, NIPSCO provided sufficiently detailed testimony and information to support its forecasted fuel costs as required by our FAC 90 Order. We find that NIPSCO should continue to include in its quarterly FAC filings detailed testimony and information regarding these five factors.

Petitioner previously made the following forecasts of its fuel cost in July, August and September 2011 and incurred the following actual costs, resulting in a percent error calculated as follows:

Month	Estimated Fuel Cost	Actual Fuel Cost	Over (Under) Estimate
July	$0.030966/kWh	$0.036825/kWh	-15.91%
August	$0.031139/kWh	$0.031232/kWh	-0.30%
September	$0.031237/kWh	$0.027128/kWh	15.15%
Weighted Average Estimating Error			**-2.01%**

Petitioners' Exhibit B, Schedule 5, pp. 1-3, Lns. 28-29; Petitioner's Exhibit B, Schedule 5, p. 4, Ln. 29.

OUCC Witness Gregory T. Guerrettaz testified nothing had come to his attention that would indicate that the projections used by NIPSCO for fuel costs and sales of power were unreasonable considering a comparison of prior quarter actual and forecast fuel costs and sales figures and his additional analysis comparing generation variance by units.

Based on NIPSCO's estimate of its prospective fuel cost and its actual fuel costs for July, August, and September 2011, we find that NIPSCO's estimate of its prospective average fuel cost is reasonable for the billing months of February, March, and April 2012.

10. **Return Earned.** Petitioner's exhibits demonstrate that for the twelve months ending September 30, 2011, Petitioner earned a jurisdictional return of $162,659,704 (Petitioner's Exhibit 2-A, p. 1, Ln. 21c, Col. F), and a 6.54% rate of return (Petitioner's Exhibit 2-B, Ln. 9) on its jurisdictional rate base from Cause No. 38045. This amount included $23,989,073 (Petitioner's Exhibit 2-A, p. lB, Ln. 1) of opportunity off-system sales made from internally generated power, offset by fuel, purchased power costs, supporting variable costs, and taxes for a net profit of $3,520,082 (Petitioner's Exhibit 2-A, p. l, Ln. 21b) in accord with the Settlement Agreement approved by the Commission in the Order dated August 23, 2006 in Cause No. 42824 Order. As shown in Petitioner's Exhibit 2-A, the jurisdictional return authorized in Cause No. 38045, adjusted for the Environmental Cost Recovery Mechanism return authorized in Cause No. 42150 ECR 18, pursuant to Indiana Code §§ 8-1-2-6.6 and -6.8, was $246,716,177 (Petitioner's Exhibit 2-A, p. 1, Ln. 21c, Col. B). Therefore, during the twelve months ending September 30, 2011, the Commission finds NIPSCO did not earn a return more than that authorized in its last base rate case, as appropriately adjusted.

11. **Earnings Subject to Sharing.** Pursuant to the Commission's September 23, 2002 Order in Cause No. 41746, NIPSCO must share the over-earnings reported in each FAC. Petitioner's Exhibit 2-A reflects that for the twelve months ending September 30, 2011, Petitioner has no such over-earnings.

12. **Fuel Cost Adjustment Factor.** As we have set forth herein, Petitioner has met the tests of Indiana Code § 8-1-2-42(d) for establishing a revised fuel cost charge. Petitioner's evidence presented a variance factor of $0.000977 per kWh (Petitioner's Exhibit B, Revised Schedule 1, Ln. 27), to be added to the estimated cost of fuel for the billing months of February, March, and April 2012, in the amount of $0.032596 per kWh (Petitioner's Exhibit B, Revised Schedule 1, Ln. 25). This results in a fuel cost charge factor of $0.004919 per kWh (Petitioner's Exhibit B, Revised Schedule 1, Ln. 32), after subtracting from that cost the cost of fuel in NIPSCO's base rates and adjusting for applicable taxes. OUCC witness Mr. Eckert testified a residential customer using 1,000 kWh per month will experience an overall increase of $1.85 on his or her electric bill from the currently approved factor. Petitioner's revised exhibits filed on December 28, 2011 included the addition of Page 2 to Exhibit B Schedule 1 to show the determination of the FAC rate for two special contracts with terms tied to the effective date of the 43969 Order. The fuel adjustment charge factor for such customers is $.011188 per kWh (Petitioner's Exhibit B, Revised Schedule 1, p.2, Ln. 4), after subtracting from that cost the cost of fuel in NIPSCO's applicable rates and adjusting for applicable taxes.

13. **Customer Credit Adjustment Factor.** Petitioner's evidence as originally submitted showed the Customer Credit Adjustment Factor percentage is calculated in accordance with the methodology prescribed in the September 23, 2002 Order in Cause No. 41746. Because

Petitioner received a base rate order in Cause No. 43969 on December 21, 2011, such a credit is no longer required.[1]

14. **OUCC Report.** Mr. Greg Guerrettaz testified: (1) NIPSCO calculated the fuel cost element of the proposed fuel cost adjustment by including additional requirements set forth in various Commission orders; (2) NIPSCO calculated a variance for the quarter ending September 2011 in conformity with the requirement of Indiana Code § 8-1-2-42; (3) NIPSCO did not have jurisdictional net operating income for the twelve months ending September 30, 2011 greater than granted in its last general rate case; (4) the fuel cost adjustment for the quarter ending September 30, 2011 has been properly applied; and (5) the figures used in the application for change in fuel cost adjustment for the quarter ending September 30, 2011 were supported by NIPSCO's books and records and source documents.

Mr. Michael Eckert testified NIPSCO's treatment of Ancillary Services Market charges follow the treatment ordered by the Commission in its Phase II Order in Cause No. 43426 dated June 30, 2009. He also testified that pursuant to the Order in Cause No. 43426, NIPSCO is continuing to recover Day Ahead RSG Distribution Amounts and Real Time RSG First Pass Distribution Amounts through the FAC. He noted NIPSCO's steam generation costs are above average in the State of Indiana and that NIPSCO's actual monthly cost of fuel (mills/kWh) is above the average in the State of Indiana. Mr. Eckert testified that the OUCC recommends the Commission approve the implementation of the NIPSCO's requested FAC factor.

15. **Purchased Power Costs Above Monthly Standard.** Mr. Williamson described the Benchmark that applies to Petitioner's purchased power transactions established in Cause No. 43526. He stated that the daily Benchmark is based upon a generic Gas Turbine ("GT"), using a generic heat rate of 12,500 btu/kwh times the gas cost determined by using the Platt's Gas Daily Midpoint price for Chicago City Gate, plus a $0.17/mmbtu gas transport charge. Mr. Williamson testified not all purchased power transactions are subject to the Benchmark—only those that are used to serve FAC load (excluding backup and maintenance contracts) as determined by NIPSCO's RCA system, including bilateral purchases for load and Midwest ISO Day Ahead and Real Time purchases, except wind power purchases which are excluded per Cause No. 43393. Swap transactions and Midwest ISO virtual transactions for generation and load are not subject to the Benchmark. Mr. Williamson testified NIPSCO did not have any swap or virtual transactions during this FAC period. Mr. Williamson testified that NIPSCO is seeking to recover 23,326.22 MWhs of purchased power in July; 8,526.88 MWhs of purchased power in August; and 2,168.84 MWhs of purchased power in September that were in excess of the Purchased Power Daily Benchmark, which were made to supply jurisdictional load that offset available NIPSCO resources that were not dispatched by the Midwest ISO or were otherwise eligible under the procedures outline in the Order in Cause No. 43526 and are therefore recoverable.

Regarding the purchased power benchmark, OUCC witness Mr. Eckert testified NIPSCO's testimony and workpapers reflect the Order in Cause No. 43526 regarding purchased power over the benchmark, and he agreed with NIPSCO's calculation of purchased power over the benchmark.

[1] The Stipulation and Settlement Agreement approved in Cause No. 43969 states (pp. 15-16) that "Upon the effective date of new rates following the issuance of a Final Order in this proceeding, the revenue credit and the sharing mechanism approved in Cause No. 41746 will cease. After reconciliations of the revenue credit have been performed for all billed months, the final balance of any over or under credit will be included in the variance in the FAC filing that follows the final revenue credit reconciliation month and shall be specifically identified."

In Cause No. 38706 FAC 90, we found that NIPSCO should use the purchased power benchmark approved in Cause No. 43526. Based on the evidence, we find that NIPSCO's identified purchase power costs are properly included in the fuel cost calculation.

16. **Interim Rates.** Because the Commission is unable to determine whether Petitioner will earn an excess return while this Order is in effect, the Commission finds that the rates approved herein should be interim rates, subject to refund.

IT IS THEREFORE ORDERED BY THE INDIANA UTILITY REGULATORY COMMISSION that:

1. Petitioner's requested fuel cost charge to be applicable to bills rendered in the months of February, March, and April 2012, as set forth in Finding No. 12 above is hereby approved on an interim basis subject to refund as set out in Finding No. 16 above.

2. Petitioner shall continue to include in its quarterly FAC filings updates concerning its utilization of the RECs associated with the wind purchases being recovered through the FAC as set out in Finding No. 7 above. NIPSCO shall also include in its quarterly FAC filings information as set out in Finding No. 9 above.

3. Petitioner shall file with the Electricity Division of the Commission, prior to placing in effect the fuel cost adjustments herein approved, an amendment to its rate schedule with reasonable reference therein reflecting that such charges are applicable to the rate schedules reflected on the amendment.

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

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

APPROVED: JAN 25 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