ORIGINAL

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY FOR APPROVAL OF A FUEL COST ADJUSTMENT TO BE APPLICABLE DURING THE BILLING CYCLES OF AUGUST, SEPTEMBER AND OCTOBER 2013, PURSUANT TO IND. CODE § 8-1-2-42 AND CAUSE NO. 43969 AND FOR APPROVAL OF RATEMAKING TREATMENT FOR COSTS INCURRED UNDER WHOLESALE PURCHASE AND SALE AGREEMENTS FOR WIND ENERGY APPROVED IN CAUSE NO. 43393.	)	CAUSE NO. 38706 FAC 99 APPROVED: JUL 31 2013

ORDER OF THE COMMISSION

Presiding Officers:
Kari A.E. Bennett, Commissioner
Jeffery A. Earl, Administrative Law Judge

On May 1, 2013, Northern Indiana Public Service Company ("NIPSCO" or "Petitioner") filed its Verified Petition in this Cause. NIPSCO also filed the direct testimony and exhibits of Katherine A. Cherven, Manager of Compliance in NIPSCO's Rates and Regulatory Finance Department, Ronald G. Plantz, Controller, Daniel T. Williamson, Executive Director of Energy Supply and Trading, Kevin A. Strnatka, Director of Fuel Supply, and Keith Anderson, Director of Business Support Services for the Generation Department. On May 17, 2013, the NIPSCO Industrial Group ("Industrial Group") filed a Petition to Intervene, which the Presiding Officers granted on May 29, 2013. On June 5, 2013, the Indiana Office of Utility Consumer Counselor ("OUCC") filed its report in this Cause along with the direct testimony and exhibits of Michael D. Eckert, Senior Utility Analyst in the OUCC's Electric Division, and Gregory T. Guerrettaz, CPA, President of Financial Solutions Group, Inc. On June 18, 2013, NIPSCO prefiled the rebuttal testimony from Mr. Anderson and Mr. Williamson. The Industrial Group did not offer evidence in this Cause.

Pursuant to notice given and published as required by law, the Commission held an evidentiary hearing in this Cause at 9:30 a.m. on June 27, 2013, in Hearing Room 224, 101 West Washington Street, Indianapolis, Indiana. Petitioner, the OUCC, and the Industrial Group appeared and participated in the hearing. No members of the general public appeared or sought to participate.

Based upon the applicable law and the evidence presented, the Commission finds:

1. <u>Commission Jurisdiction and Notice</u>. Notice of the hearing in this Cause was given and published by the Commission as required by law. Petitioner is a public utility as that term is defined in Ind. Code § 8-1-2-1(a). Under Ind. Code § 8-1-2-42, the Commission has jurisdiction over changes to Petitioner's fuel cost charge. Therefore, the Commission has jurisdiction over Petitioner and the subject matter of this Cause.

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2. **Petitioner's Characteristics**. Petitioner has its principal office at 801 East 86th Avenue, Merrillville, Indiana. Petitioner renders 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**. Petitioner's cost of fuel to generate electricity and the cost of fuel included in the cost of purchased electricity in Petitioner's last base rate case approved in the Commission's December 21, 2011 Order in Cause No. 43969 ("43969 Order") was $0.028729 per kWh. Petitioner's cost of fuel to generate electricity and the cost of fuel included in the cost of purchased electricity for the months of January, February, and March 2013 averaged $0.028705 per kWh.

4. **Requested Fuel Cost Charge**. Petitioner seeks to change its fuel cost adjustment charge from the current charge of $0.000953 per kWh to a charge of $0.000713 per kWh for bills rendered during the billing cycles of August, September, and October 2013.

The requested fuel cost adjustment includes a variance of $7,824,470 that was over-collected during January, February, and March 2013. Petitioner's estimated monthly average cost of fuel to be recovered in this proceeding for the forecast period of July, August, and September 2013 is $45,804,148, and its estimated monthly average sales for that period are 1,494,396 MWh.

5. **Statutory Requirements**. Ind. Code § 8-1-2-42(d) states that the 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;
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> (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;
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> (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.
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> (4) The utility's estimates of its prospective average 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, shows that fuel costs for the twelve months ending March 31, 2013, were $29,684,402 above the levels approved in the 43969 Order. Petitioner's Exhibit 2-A also shows that the total operating expenses excluding fuel for the twelve months ending March 31, 2013, were $114,280,159 above the levels approved in the 43969 Order. The Commission finds that Petitioner's actual increase in fuel costs for the twelve months ending March 31, 2013, 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.** Mr. 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 for the three months ended March 31, 2013, was coal (78.30%) and the remainder was natural gas (21.70%).

a. **Fuel Procurement.** 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, sulfur content, mercury content, and the economic and technical suitability of certain low-cost fuels to be blended at NIPSCO's generating units to maintain the lowest, reasonably possible 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 has four long-term contracts in 2013. He stated 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 market, 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 that increase each year. He stated that one long-term contract has prices that are adjusted annually for the succeeding year based on the average weekly indexed prices of that particular coal in the previous year, and one long-term contract has an annual market price reopener that will determine the contract coal price for the succeeding year of the contract.

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 March 31, 2013, was $51.45 per ton or $2.54 per million Btu. The delivered coal cost for January, February, and March 2013 ("the reconciliation period") was $53.50 per ton or $2.616 per million Btu. Mr. Strnatka stated NIPSCO made no spot purchases during the reconciliation period. He testified that the average market spot price of coal (excluding transportation costs) during the reconciliation period was $10.53 per ton for Powder River Basin ("PRB") coal, $37.82 per ton for Illinois Basin ("ILB") high sulfur coal, and $60.33 per ton for Pittsburgh #8 ("Pitt#8") coal.

Mr. Strnatka testified that coal supply during the reconciliation period continued to be impacted by natural gas pricing and weak coal demand in both the domestic and international markets. Consequently, spot market pricing across all coal regions remained relatively soft. In addition, the colder than normal weather in March 2013 had a greater impact on coal consumption. Mr. Strnatka testified that NIPSCO's delivered cost of coal during the reconciliation period increased compared to the fourth quarter of 2012 from $50.21 per ton or $2.493 per million Btu to $53.50 per ton or $2.616 per million Btu. He stated this increase was largely attributed to a planned dumper outage at the R.M. Schahfer Generating Station, which prohibited NIPSCO from taking economical PRB coal for an extended period of time, and the transition to new coal and transportation contract pricing for the calendar year 2013. Mr. Strnatka testified that fuel surcharges remained relatively flat during the reconciliation period.

Petitioner's witness Williamson stated NIPSCO does not purchase natural gas under multiple-year contracts. Instead, physical natural gas supplies are purchased on a spot basis when NIPSCO's gas-fired generation units are either economical to run or need to run for operational purposes. Mr. Williamson testified that NIPSCO has made every reasonable effort to purchase natural gas so as to provide electricity to customers at the lowest reasonable price.

b. Renewable Energy Credits ("RECs"). With respect to NIPSCO's efforts to maximize the value of RECs for its customers, Mr. Williamson stated that Indiana does not currently have regulations that guide the certification and accounting for RECs. Consequently, NIPSCO has held the RECs on account with M-RETS in the event that the State of Indiana were to approve a renewable energy standard, and due to the RECs' relatively low market value. He noted the Indiana General Assembly passed Senate Bill 251 in 2011, which includes a voluntary renewable energy standard and the Commission conducted a rulemaking process to implement it. He testified that NIPSCO monitored the results of that legislation and rulemaking and is making changes in the way it utilizes RECs.

Mr. Williamson provided an update on NIPSCO's treatment of RECs. He stated that NIPSCO's recent vintage RECs have significantly more value in regions of the market than older vintage RECs. Mr. Williamson testified NIPSCO has begun offering these recently acquired RECs to the renewable energy market when it acquires a minimum of 50,000, which is the standard REC contract. He stated that the amount of time it takes to accumulate a block of 50,000 RECs varies based on the MW output at the wind resources and noted that historically this has been roughly every two months. He stated the goal behind this method is to spread the sales of RECs over multiple time periods throughout the year. He stated that because the RECs market can at times be very illiquid, there is no guarantee that a sale transaction will occur at the time the 50,000 RECs are offered. Mr. Williamson testified NIPSCO will pass the proceeds from the sale of RECs back to customers through the "Purchased Power other than MISO" line item. He stated that NIPSCO continues to monitor and evaluate the marketability for all vintage RECs, potential future legislation that would consider NIPSCO's RECs as eligible to meet state renewable energy standards, and the Commission's Voluntary Clean Energy Portfolio Standard program rules and that NIPSCO will make appropriate changes as necessary. NIPSCO shall 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.

c. **Electric Hedging Program.** Mr. Williamson testified NIPSCO incorporated the Electric Hedging Program that was approved by the Commission's July 13, 2011 Order in Cause No. 43849 ("43849 Order") in this FAC proceeding. He testified that in January, NIPSCO purchased 71 gas contracts and 22 power contracts, in February, NIPSCO purchased 50 gas contracts and no power contracts, and in March, NIPSCO purchased 61 gas contracts and no power contracts. He stated that the execution of these contracts is consistent with NIPSCO's hedging plan. Mr. Williamson stated that the impact of the hedges entered into for the Electric Hedging Program for this proceeding was a loss of $394,843 during the reconciliation period, plus broker fees and clearing exchange fees which totaled $4,139 during the reconciliation period, for a total impact of the hedging program in this proceeding of $398,982 during the reconciliation period. He noted that broker fees represented 0.03% of the total value of the transactions that occurred during this reconciliation period. Mr. Williamson testified decisions were made based upon the conditions known at the time of the transactions and NIPSCO used the same broker it uses for its other transactions to limit transaction costs. NIPSCO shall continue to include in its filings testimony and evidence of its electric hedging costs, and any gains/losses resulting from its hedging transactions for which it is seeking recovery through the FAC.

d. **Purchased Power Over The Benchmark.** Mr. Williamson described the Benchmark that applies to Petitioner's purchased power transactions established in the Commission's August 25, 2010 Order in Cause No. 43526 ("43526 Order"). Mr. Williamson testified that NIPSCO did not have any swap or virtual transactions during this FAC period. Mr. Williamson testified that NIPSCO is seeking to recover 759.65 MWhs of purchased power in February 2013 that were in excess of the Purchased Power Daily Benchmark. Mr. Williamson testified that in accordance with the procedures outlined in the 43526 Order, the Purchases over the Purchased Power Benchmark were made to supply jurisdictional load that offset available NIPSCO resources that were not dispatched by MISO or were otherwise eligible under the procedures outlined in the 43526 Order and are therefore recoverable.

Mr. Eckert testified that Mr. Williamson's testimony and workpapers reflect the 43526 Order regarding purchased power over the benchmark and that he agreed with Mr. Williamson's calculation of purchased power over the benchmark. Based on the evidence, we find that NIPSCO's identified purchase power costs are properly included in the fuel cost calculation.

Based on the evidence and our discussion above, we find that 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. **MISO Day 2 Energy Costs.** NIPSCO included in its forecast the operational charges associated with the MISO Day 2 energy market, in accordance with the Commission's Orders in Cause Nos. 42685, 43426 and 43665. The total "MISO Components of Fuel Cost" included in the actual cost of fuel for the reconciliation period was ($1,679,348).

9. **Interruptible Credits.** Mr. Williamson testified the 43969 Order approved Rider 675 – Interruptible Industrial Service, which provides for credits to be paid to certain industrial customers that agree to interrupt their service if certain criteria are met. Mr. Williamson stated that during the reconciliation period, NIPSCO did not interrupt any of the industrial customers taking service under Rider 675. The evidence shows that NIPSCO paid a total of $9,420,288 in interruptible credits through Rider 675 during the reconciliation period and, pursuant to the 43969 Order, NIPSCO is authorized to recover twenty-five percent (25%) of that total, or $2,355,072, through the FAC for the billing months of August, September, and October 2013

10. **Estimation of Fuel Cost.** Petitioner estimated that its prospective total average fuel costs for the months of July, August, and September 2013 will be $45,804,148 on a monthly basis.

Mr. Strnatka testified that NIPSCO anticipates that its delivered coal cost during the forecast period of July, August, and September 2013 will be approximately $51.37 per ton or an estimated $2.59 per million Btu. Mr. Strnatka testified the average spot market prices for calendar year 2014 (which do not include cost of transportation) are currently $12.28 per ton for PRB coal, $39.51 per ton for ILB coal and $62.06 per ton for Pitt#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 PROMOD.

Mr. Strnatka cited the price of natural gas and weather as the factors NIPSCO believes will have the greatest impact on the supply, demand, and cost of coal during the forecast period. He testified that currently natural gas pricing is above $4/mmBtu and appears to be poised to stay at this level, effectively causing coal-fired generation to be more competitive. Also, with the abnormal weather experienced in the Spring and the possibility of a warm Summer, demand for coal could increase, raising prices accordingly. He stated that NIPSCO had two transportation agreements that expired at the end of 2012. He stated that in FAC 98 NIPSCO indicated that one of the transportation agreements would not be needed for Bailly Generating Station because NIPSCO was anticipating supplying both this station and R.M. Schahfer Generating Station with ILB coal shipped by the same rail carrier. However, NIPSCO has burned through its excess inventory more quickly than anticipated and is now preparing to competitively bid coal and transportation requirements for supplying Bailly Generating Station. Also, NIPSCO has agreed to term, tons, and rates with the second transportation provider, but both parties continue to negotiate an open contractual item that requires closure. NIPSCO and the transportation provider agreed to extend the negotiation period initially to March 31, and again to May 31, in an effort to provide both parties sufficient time to finalize the negotiation, or to move in another direction. Currently, both parties are continuing to discuss potential resolutions to this unresolved item. All other term transportation agreements that carried over to 2013 had annual contractual transportation price increases that commenced January 1, 2013. He stated these price increases effectively raised the delivered cost of coal in 2013 and will be in effect through the entire year. The prices of WTI crude and On Highway Diesel fuel have remained relatively stable, therefore NIPSCO's delivered coal cost will be minimally influenced by fuel surcharges paid to the railroads.

Mr. Strnatka testified NIPSCO does not anticipate any issues in securing coal or transportation during the forecast period. Due to much higher than anticipated coal consumption experienced in March and April and continued anticipated higher consumption through the forecast period, NIPSCO will be soliciting for high sulfur coal and transportation in the very near future. He stated that because of this increase in coal consumption experienced in March, and so far in April, NIPSCO's total coal inventory is currently within the normal range of its system target. NIPSCO will continue to supply both Bailly Generating Station and R.M. Schahfer Generating Station from its one ILB contract until additional high sulfur coal and transportation is secured for Bailly Generating Station. Then based on inventory, NIPSCO will decide whether to continue serving both Bailly Generating Station and R.M. Schahfer Generating Station with its one ILB contract, or revert all future coal deliveries from its ILB contract to its original destination, R.M. Schahfer Generating Station

In our April 27, 2011 Order in Cause No. 38706 FAC 90, we ordered NIPSCO to provide detailed testimony and information regarding: (1) the 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 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 January, February, and March 2013 and incurred the following actual costs, resulting in a percent error calculated as follows:

Month	Estimated Fuel Cost	Actual Fuel Cost	Over (Under) Estimate
January	$0.031523/kWh	$0.028891/kWh	9.11%
February	$0.031141/kWh	$0.027903/kWh	11.60%
March	$0.030528/kWh	$0.029276/kWh	4.28%
Weighted Average Estimating Error			**8.23%**

Mr. Guerrettaz testified that 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. He also testified that the OUCC had a detailed, sit down meeting during the onsite audit during which NIPSCO provided documentation of the updated gas and coal costs to verify what changes had occurred since the forecast was prepared. He stated considerable changes in the forecast have occurred in the coal cost area, which should have a positive impact on the FAC factor going forward.

Based on NIPSCO's estimate of its prospective fuel cost and its actual fuel costs for January, February, and March 2013, we find that NIPSCO's estimate of its prospective average fuel cost to be recovered during the August, September, and October 2013 billing cycles is reasonable.

11. **Return Earned.** Petitioner's exhibits demonstrate that for the twelve months ending March 31, 2013, Petitioner earned a return of $176,689,409. This is less than the authorized return of $198,275,394 approved in Cause No. 43969 plus NIPSCO's actual Environmental Cost Recovery Mechanism operating income during the twelve months ended March 31, 2013. Mr. Plantz testified that consistent with the August 22, 2012 Order in Cause No. 44156 RTO 1, NIPSCO excluded operating revenues and O&M expenses adjusted for taxes associated with NIPSCO's MVP projects for the purpose of Petitioner's Exhibit No. 2-A. Based on the evidence presented, the Commission finds that for the twelve months ending March 31, 2013, NIPSCO did not earn a return more than that authorized in its last base rate case, as appropriately adjusted.

12. **Fuel Cost Adjustment Factor.** Petitioner has met the tests of Ind. Code § 8-1-2-42(d) for establishing a revised fuel cost adjustment. Petitioner's evidence presented a variance factor of $(0.001745) per kWh and a recoverable interruptible factor of $0.000525 per kWh to be added to the estimated cost of fuel for bills rendered during the billing cycles of August, September, and October 2013, in the amount of $0.030651 per kWh. This results in a fuel cost adjustment factor of $0.000713 per kWh , after subtracting the cost of fuel in NIPSCO's base rates and adjusting for applicable taxes. Mr. Eckert calculated that a residential customer using 1,000 kWh per month will experience an overall decrease of $0.24 on his or her electric bill from the currently approved factor.

13. **OUCC Report.** Mr. Guerrettaz testified that: (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 March 31, 2013, in conformity with the requirement of Ind. Code § 8-1-2-42; (3) NIPSCO did not have jurisdictional net operating income for the twelve months ending March 31, 2013, greater than granted in its last general rate case; (4) the fuel cost adjustment for the quarter ending March 31, 2013, has been properly applied; and (5) the figures used in the application for change in fuel cost adjustment for the quarter ending March 31, 2013, were supported by NIPSCO's books and records and source documents. He also testified that in this FAC, in February, the estimated mix of generation was off from actual a significant amount due to outages. He stated the mix of generation changed noticeably during this actual period from a forecast of 1,160,762 MWHs to an actual of 702,840 MWHs for steam generation. This meant that the actual mix of MWHs and costs were quite different from that previously forecasted. Mr. Guerrettaz testified the OUCC is continuing to monitor events such as weather and outages that appear to change the results most significantly.

Mr. Eckert testified that: (1) he reviewed and agreed with Mr. Williamson's purchased power over the benchmark calculation; (2) NIPSCO's treatment of Ancillary Services Market ("ASM") charges follows the treatment ordered by the Commission in its Phase II Order in Cause No. 43426 dated June 30, 2009 ("Phase II Order"); (3) NIPSCO is continuing to recover Day Ahead Revenue Sufficiency Guarantee ("RSG") Distribution Amounts and Real Time RSG First Pass Distribution Amounts through the FAC pursuant to the Phase II Order; (4) NIPSCO has reported the average monthly ASM cost Distribution Amounts for Regulation, Spinning and Supplemental Reserves charges types pursuant to the Phase II Order; (5) 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 among the lowest in the State of Indiana; (6) NIPSCO's coal inventory is within normal target levels and the OUCC will continue to monitor and inform the Commission about NIPSCO's coal inventory in future FAC filings; and (7) the OUCC reviewed NIPSCO's hedges and believes the hedging costs were reasonable.

Mr. Eckert also testified that he reviewed the forced outage schedule attached to Mr. Anderson's testimony as Petitioner's Exhibit No.5-A. RMS 17 had a forced outage in February 2013 due to a steam leak caused by an incorrect sized gasket. The unit was offline for 78 hours. He testified that the OUCC issued a data request regarding the Unit 17 Outage in which it asked how much purchased power was bought to replace the lost power from the Unit 17 Outage and whether NIPSCO sought reimbursement from GE for the cost of the Purchased Power that replaced the power lost due to the Unit 17 Outage. He testified that NIPSCO had not provided responses to that data request but acknowledged that the data request was not due until June 10, 2013. He recommended that NIPSCO's FAC be made interim subject to refund until the OUCC receives more information on the Unit 17 Outage.

In response to Mr. Eckert's testimony, NIPSCO witness Mr. Anderson testified NIPSCO submitted its Objections and Responses to the OUCC Auditors Data Request Set 2 in Cause No. 38706 FAC 99 on June 6, 2013. Mr. Anderson explained the statement in his direct testimony that GE was held accountable for the valve leaks since they did not verify the fit of the OD into the steam chest casing. He explained that the Specification for the 2012 Maintenance and Inspection of Unit 17 Turbine and Ancillary Equipment at R.M. Generating Station ("Specification") sets forth GE's responsibility for the inspection and maintenance of Unit 17's turbine and ancillary equipment and provides that GE will be responsible for costs associated with all necessary rework required to correct certain performance issues. NIPSCO met with GE on February 9, 2013 to discuss the steam leak that caused the Unit 17 Outage. Both GE and NIPSCO agreed the valve would need to be disassembled with both parties in attendance to positively identify the cause of the leak. Upon measuring the gasket, it was discovered the gasket was too big. After this inspection, both parties agreed that GE was responsible for the cost of remediating the problem pursuant to the Specification. GE subsequently replaced the failed gasket with a properly sized gasket. Mr. Anderson testified GE was only responsible for the cost of the repairs and was not responsible for any monetary damages.

14. <u>Interim Rates</u>. Because we are unable to determine whether Petitioner will earn an excess return while this Order is in effect, we find 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 adjustment to be applicable to bills rendered during the billing cycles of August, September, and October 2013, as discussed in Paragraph 12 above, is approved on an interim basis subject to refund as discussed in Paragraph 14 above.

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

3. 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 discussed in Paragraph 7(b) above, and testimony regarding any electric hedging transaction costs and gains/losses for which it is seeking recovery through the FAC, as discussed in Paragraph 7(c) above. Petitioner shall also include in its quarterly FAC filings the information required by the Commission's April 27, 2011 Order in Cause No. 38706 FAC 90, as discussed in Paragraph 10 above.

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

ATTERHOLT, BENNETT, LANDIS, MAYS AND ZIEGNER CONCUR:

APPROVED: JUL 31 2013

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