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STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

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| **PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY FOR APPROVAL OF A FUEL COST ADJUSTMENT TO BE APPLICABLE DURING THE BILLING CYCLES OF MAY, JUNE AND JULY 2014, 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 102**<br><br>**APPROVED:** APR 30 2014 |

**ORDER OF THE COMMISSION**

**Presiding Officer:**
**Jeffery A. Earl, Administrative Law Judge**

On January 30, 2014, Northern Indiana Public Service Company ("NIPSCO") filed its Verified Petition in this Cause, seeking approval of a fuel cost adjustment to be applicable for bills rendered during the billing cycles of May, June, and July 2014. NIPSCO also prefiled its direct testimony and exhibits of the following:

- Katherine A. Cherven, Manager of Compliance in the Rates and Regulatory Finance Department;
- Ronald G. Plantz, Controller;
- Andrew S. Campbell, Manager of Planning and Regulatory Support;
- Shirley Lowry, Manager, Fuel Supply; and
- David Saffran, Generation Business Systems Administrator in the Operations Management Reporting Division.

On February 6, 2014, the NIPSCO Industrial Group ("Industrial Group") filed a Petition to Intervene, which the Presiding Officer granted. The Industrial Group did not prefile evidence in this Cause. On March 6, 2014, the Indiana Office of Utility Consumer Counselor ("OUCC") filed the direct testimony and exhibits of the following:

- Michael D. Eckert, Senior Utility Analyst in the OUCC's Electric Division; and
- Gregory T. Guerrattaz, CPA, President of Financial Solutions Group, Inc.

On March 19, 2014, NIPSCO filed the rebuttal evidence from Mr. Campbell.

The Commission held an evidentiary hearing at 9:30 a.m. on April 8, 2014, in Hearing Room 224, 101 W. Washington Street, Indianapolis, Indiana. NIPSCO, the OUCC, and the

Industrial Group appeared at 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, we find:

1. **Commission Jurisdiction and Notice.** Notice of the evidentiary hearing in this Cause was given and published as required by law. NIPSCO 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 NIPSCO's fuel cost charge. Therefore, the Commission has jurisdiction over NIPSCO and the subject matter of this Cause.

2. **NIPSCO's Characteristics.** NIPSCO has its principal office at 801 East 86th Avenue, Merrillville, Indiana. NIPSCO 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 electric utility service to the public.

3. **Available Data on Actual Fuel Costs.** NIPSCO's cost of fuel to generate electricity and the cost of fuel included in the cost of purchased electricity in NIPSCO'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. NIPSCO's cost of fuel to generate electricity and the cost of fuel included in the cost of purchased electricity for the months of October, November, and December 2013 averaged $0.031723 per kWh.

4. **Requested Fuel Cost Charge.** NIPSCO seeks to change its fuel cost adjustment charge from the current charge of $0.003221 per kWh to a charge of $0.003779 per kWh, for bills rendered during the billing cycles of May, June, and July 2014.

The requested fuel cost adjustment includes a variance of $2,709,591 that was under-collected during October, November, and December 2013. NIPSCO's estimated monthly average cost of fuel to be recovered in this proceeding for the forecast period of April, May, and June 2014 is $43,359,453, and its estimated monthly average sales for that period are 1,387,939 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;
>
> (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 average fuel costs for each such three calendar months are reasonable after taking into considerations: (A) the actual fuel costs experienced by the utility during the latest three calendar months for which actual fuel costs are available; and (B) the estimated fuel costs for the same latest three calendar months for which actual fuel costs are available.

**6. Fuel Costs and Operating Expenses.** Petitioner's Exhibit No. 2-A, shows that fuel costs for the 12 months ending December 31, 2013, were $66,578,163 above the levels approved in the 43969 Order, the last proceeding in which NIPSCO's basic rates and charges for electric service were approved. Petitioner's Exhibit No. 2-A also shows that the total operating expenses excluding fuel for the 12 months ending December 31, 2013, were $100,205,712 above the levels approved in the 43969 Order. The Commission finds that NIPSCO's actual increase in fuel costs for the 12 months ending December 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.** Ms. Lowry 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. She testified that NIPSCO's primary fuel for generation of electric energy is coal (77.60%) and the remainder is natural gas (22.40%) for the three months ended December 31, 2013.

**A. Fuel Procurement.** With respect to NIPSCO's coal procurement process, Ms. Lowry 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, 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 "as-burned" fuel cost. NIPSCO also considers the availability, reliability, and diversity of particular coal suppliers and coal transporters in its fuel procurement practices. NIPSCO had four long-term contracts in 2013. Ms. Lowry said that NIPSCO would meet any remaining coal requirements through spot purchases. Ms. Lowry explained that NIPSCO competitively bids all coal purchased under a long-term agreement. She 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. 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. NIPSCO negotiates price and commercial terms and conditions with the low evaluated bidder(s).

Ms. Lowry 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. Two of NIPSCO's long-term contracts have firm prices that increase each year as set out in the contract. 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.

Ms. Lowry 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. 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. 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.

Ms. Lowry testified that the delivered cost of coal for NIPSCO for the 12 months ending December 31, 2013, was $50.45 per ton or $2.494 per million Btu. The delivered coal cost for the reconciliation period (October, November, and December 2013) was $50.84 per ton or $2.465 per million Btu. NIPSCO did not make any spot coal purchases for the period October through December, 2013. The average spot market price of coal (excluding transportation costs) during the reconciliation period was $11.30 per ton for Powder River Basin ("PRB") coal, $39.34 per ton for Illinois Basin high sulfur coal ("ILB"), and $61.91 per ton for Pittsburgh #8 ("Pitt8") coal.

With respect to the market factors affecting the supply, demand, and cost of coal during the reconciliation period, Ms. Lowry testified that coal supply during the reconciliation period continued to be impacted by weather, natural gas pricing, and weak coal demand in the domestic market. Consequently, spot market pricing across all coal regions continues to remain relatively soft. NIPSCO's delivered cost of coal during the reconciliation period increased compared to the third quarter of 2013 from $49.11 per ton or $2.432 per million Btu to $50.84 per ton or $2.465 per million Btu. NIPSCO had a rotary car dumper replacement at the Michigan City Generating Station and a coal handling conveyor chute maintenance and replacement at R. M. Schahfer Generating Station Units 14/15 coal handling, which impacted the receiving and dumping of coal shipments. Due to these events, NIPSCO dumped significantly less lower-cost PRB coal during the reconciliation period.

Mr. Campbell 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. The only future contracts entered into are financial hedges in accordance with the Commission's order in Cause No. 44205 S1. Mr. Campbell testified NIPSCO has made every reasonable effort to purchase natural gas so as to provide electricity to customers at the lowest reasonable price.

Based on the evidence presented, we find that NIPSCO has adequately explained its coal and gas procurement decision making and we find that its acquisition process is reasonable.

**B. <u>Renewable Energy Credits ("RECs")</u>.** Mr. Campbell provided an update on NIPSCO's treatment of RECs associated with the energy NIPSCO purchases under the wind purchased power agreements. NIPSCO's recent vintage RECs have significantly more value in regions of the market than older vintage RECs. NIPSCO has been offering these recently acquired RECs to the renewable energy market when it acquires a minimum of 50,000, which is the standard REC contract. The amount of time it takes to accumulate a block of 50,000 RECs varies based on the MW output at the wind resources: historically, this has been roughly every two months. The goal behind this method is to spread the sales of RECs over multiple time periods throughout the year. 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. During this FAC period a block of 50,000 RECs was sold with a net proceed of $55,775. NIPSCO will pass the proceeds from the sale of RECs back to customers through the "Purchased Power other than MISO" line item. 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 NIPSCO will make appropriate changes as necessary.

Mr. Campbell provided an update on the treatment of RECs received from feed-in-tariff purchases. NIPSCO is currently determining the most appropriate way to account for, reconcile, and market the RECs received from feed-in purchases. Any sale of these RECs will be passed back through the FAC.

Finally, Mr. Campbell explained NIPSCO's proposal to transfer RECs at market price from the account for NIPSCO's FAC customers to the GPR program. Consistent with the Commission's December 30, 2013 Order in Cause No. 44198 GPR 2 ("GPR-2"), NIPSCO is requesting authority to transfer at market price the RECs obtained in conjunction with wind energy purchases under NIPSCO's wind purchase power agreements with Barton and Buffalo Ridge I Wind Farms to the GPR program. These RECs are currently held in an account for NIPSCO's customers who pay the fuel adjustment clause ("FAC RECs"). The proposed REC procurement measure will allow NIPSCO's GPR customers the opportunity to purchase small lot volumes at large block market prices. FAC customers will continue to sell large lots at the wholesale level, receive wholesale pricing, and receive current large block market pricing. FAC customers will gain the benefit through the avoidance of brokerage commission fees that are charged during third party sales. NIPSCO will pass the proceeds from the transfer of the REC's back to FAC customers in the quarterly FAC filings. Mr. Campbell explained how the transaction to transfer vintage FAC RECs would take place. An accounting entry will be made to transfer RECs at market price to the GPR program cost account and an offsetting credit will be recorded in an account for the cost of the FAC RECs for the FAC customers. Proceeds from the transaction will be credited to all FAC customers.

Mr. Guerrettaz testified that the OUCC does not foresee any issues with NIPSCO's proposal to transfer RECs at market price from the account for NIPSCO's FAC customers to the GPR program so long as the market price can be established. Mr. Guerrettaz stated that each utility already provides the OUCC market pricing information to verify the prices at which the RECs are sold to a third party and that in each audit, this information is reviewed onsite and discussion takes place on the prices used for the sale. Mr. Guerrettaz testified that the market is limited and there is always a range in prices.

In rebuttal, Mr. Campbell sponsored Petitioner's Exhibit No. 3-R1 to clarify NIPSCO's proposal regarding how the market price of RECs would be determined. NIPSCO proposes that the market price of RECs sold to GPR customers will be equal to the wholesale large block market price NIPSCO receives from the open market for the most recent sale of RECs, where the GPR customers will pay for any retirement fees associated with the transfer. NIPSCO is requesting that the Commission approve its proposal to transfer RECs at market price from the account for NIPSCO's FAC customers to the GPR program and clarify that the market price of such transfers should be equal to the wholesale large block market price NIPSCO receives from the open market for the most recent sale of RECs, where the GPR customers will pay for any retirement fees associated with the transfer.

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. <u>Electric Hedging Program</u>.** Mr. Campbell testified that NIPSCO incorporated the Electric Hedging Program that was approved by the Commission's July 13, 2011 in Cause No. 43849 ("43849 Order") in this FAC proceeding. In October, NIPSCO purchased 71 gas contracts and 253 power contracts, in November, NIPSCO purchased 30 gas contracts and 120 power contracts and in December, NIPSCO purchased 31 gas contracts and 42 power contracts. The execution of these contracts is consistent with NIPSCO's currently-effective electric hedging plan approved in Cause No. 44205-S1. The impact of the hedges entered into for the Electric Hedging Program for this proceeding was a loss of $314,978 during the reconciliation period. The net total impact of the hedging program in this proceeding of $318,847 during the reconciliation period. Broker fees represented 0.05% of the total value of the transactions that occurred during this reconciliation period. Mr. Campbell 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, and the transactions were all made in accordance with the 44205 S1 Order. 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. <u>Purchased Power Over The Benchmark</u>.** Mr. Campbell described the Benchmark that applies to NIPSCO's purchased power transactions established in the Commission's August 25, 2010 Order in Cause No. 43526 ("43526 Order"). NIPSCO did not have any swap or virtual transactions during this FAC period. NIPSCO is seeking to recover 2,492.38 MWhs of purchased power in October 2013, 5,666.15 MWhs of purchased power in November 2013 and 2,287.53 MWhs of purchased power in December 2013 that were in excess of the Purchased Power Daily Benchmark. 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. Campbell's testimony and workpapers comply with the 43526 Order regarding purchased power over the benchmark and that he agreed with Mr.

Campbell'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, we find that NIPSCO 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. We also find that NIPSCO's proposal to transfer RECs at market price from the account for NIPSCO's FAC customers to the GPR program is reasonable, and we approve the proposal. The market price of such transfers shall be equal to the wholesale large block market price NIPSCO receives from the open market for the most recent sale of RECs, where the GPR customers will pay for any retirement fees associated with the transfer.

**8. MISO Day 2 Energy Costs.** NIPSCO included in its forecast the operational changes 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 Cost of Fuel" included in the actual cost of fuel for the months of October, November and December 2013 was $4,833,222.

**9. Interruptible Credits.** Mr. Campbell 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. During the reconciliation period, NIPSCO did initiate interruptions 2 separate days for a total of 28 hours under Option C and 5 hours under Option D. The evidence shows that NIPSCO paid a total of $9,331,256 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 $2,332,814, through the FAC for the billing months of May, June, and July 2014.

**10. Estimation of Fuel Cost.** NIPSCO estimated that its prospective total average fuel costs for the months of May, June and July 2014 will be $43,359,453 (Pet.'s Ex. B, Sch. 1, Ln. 24) on a monthly basis.

Ms. Lowry testified that NIPSCO anticipates that its delivered coal cost during the forecast period of April, May and June 2014 will be approximately $49.26 per ton or an estimated $2.504 per million Btu. The average spot market prices for calendar year 2014, excluding transportation, are currently $11.64 per ton for PRB coal, $39.37 per ton for ILB coal and $62.63 per ton for Pitt8 coal.

Ms. Lowry 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.

Ms. Lowry stated NIPSCO has coal supply agreements for 2014 with firm pricing; however if NIPSCO experiences a strong spring, spot coal purchases may be needed to supplement term coal purchases. If spot coal purchases are required, the price of natural gas and the winter weather will have an impact on the supply, demand, and cost of coal during the forecast period. As of January 16, 2014, natural gas pricing is between \$4.45/mmBtu and \$5.00/mmBtu, and if the pricing stays at this level during the forecast period, the demand for coal fired generation and for coal will increase. NIPSCO has transportation agreements in effect for 2014 with firm pricing (exclusive of fuel surcharges) so there will be no transportation price increases in the forecast period. If the prices of West Texas Intermediate crude remain relatively stable, NIPSCO's delivered coal cost will be minimally influenced by fuel surcharges paid to the railroads.

Ms. Lowry testified NIPSCO does not anticipate any issues in securing coal or transportation during the forecast period. NIPSCO recently entered into new coal and transportation contracts for ILB coal for Bailly Generating Station commencing January 1, 2014. Additionally, NIPSCO is currently negotiating a contract for PRB coal for Michigan City Generating Station and Units 14/15 at R. M. Schahfer Generating Station for 2014. She stated the challenge will be to manage NIPSCO's inventory. Although NIPSCO's system inventory is currently below target level due to the demand for coal fired generation in the reconciliation period being greater than forecasted, extended dumper outages, and weather-related events that led to shipment and dumping delays, NIPSCO is working with coal and transportation suppliers to increase shipments in the upcoming months to resume target inventory levels.

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.

NIPSCO previously made the following forecasts of its fuel cost in October, November and December 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 |
|---|---|---|---|
| **October** | \$0.030941/kWh | \$0.031098/kWh | -0.50% |
| **November** | \$0.031409/kWh | \$0.032053/kWh | -2.01% |
| **December** | \$0.031271/kWh | \$0.032002/kWh | -2.28% |
| **Weighted Average Estimating Error** | | | **-1.63%** |

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 during the onsite audit, he prepared a detailed analysis of the forecast workpapers which was updated from FAC101. He stated that related to the forecast and the reduction in coal prices, the OUCC continues to review any coal or transportation price solicitations and that NIPSCO, like several other utilities, has been able to reduce prices as a result of market changes.

Based on the evidence presented, including NIPSCO's estimate of its prospective fuel cost and its actual fuel costs for October, November and December 2013, we find that NIPSCO's estimate of its prospective average fuel cost to be recovered during the May, June, and July 2014 billing cycles is reasonable.

11. **Return Earned.** NIPSCO's exhibits demonstrate that for the 12 months ending December 31, 2013, NIPSCO earned operating income including ECRM revenues of $184,888,111. This is less than NIPSCO's authorized amount of $212,931,402 approved in Cause No. 43969 plus NIPSCO's actual Environmental Cost Recovery Mechanism operating income during the 12 months ended December 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 NIPSCO's Exhibit No. 2-A. Based on the evidence presented, we find that during the 12 months ending December 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.** NIPSCO has met the tests of Ind. Code § 8-1-2-42(d) for establishing a revised fuel cost adjustment. NIPSCO's evidence presented a variance factor of $0.000651 per kWh and a recoverable interruptible factor of $0.000560 per kWh to be added to the estimated cost of fuel for bills rendered during the billing cycles of May, June, and July 2014, in the amount of $0.031240 per kWh. This results in a fuel cost adjustment factor of $0.003779 per kWh, after subtracting from that cost the cost of fuel in NIPSCO's base rates and adjusting for applicable taxes. Mr. Eckert's testimony shows that a residential customer using 1,000 kWh per month will experience an overall increase of $0.56 on his or her electric bill from the currently approved factor.

13. **OUCC Report.** Mr. 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 December 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 12 months ending December 31, 2013 greater than granted in its last general rate case; (4) the fuel cost adjustment for the quarter ending December 31, 2013 has been accurately applied; and (5) the figures used in the application for change in fuel cost adjustment for the quarter ending December 31, 2013 were supported by NIPSCO's books, records and source documents.

Mr. Eckert testified: (1) he reviewed and agreed with Mr. Campbell's purchased power over the benchmark calculation; (2) NIPSCO's treatment of Ancillary Services Market 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 below normal target levels due to the recent weather and the OUCC will continue to monitor and inform the Commission about NIPSCO's coal inventory in future FAC filings; (7) the OUCC reviewed NIPSCO's hedges and believes the hedging costs were reasonable; (8) NIPSCO is seeking full recovery of the wind invoices for energy received and at this time NIPSCO is not seeking recovery of the portion of curtailed invoices that it did not pay; and (9) the OUCC recommends NIPSCO be allowed to recover the wind invoice amount for energy received and NIPSCO not be allowed to recover the portion of the wind invoice amounts for curtailed energy that NISPCO disputes and has not paid until the dispute has been settled and NIPSCO pays the bill.

**14. <u>Interim Rates</u>.** Because the Commission is unable to determine whether NIPSCO 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.

**15. <u>Confidential Information</u>.** On January 30, 2014, NIPSCO filed a motion for protective order which was supported by affidavit showing documents to be submitted to the Commission were trade secret information within the scope of Ind. Code §§ 5-14-3-4(a)(4) and (9) and Ind. Code § 24-2-3-2. The Presiding Officers issued a Docket Entry on February 12, 2014, finding such information to be preliminarily confidential. We find that all such information is confidential pursuant to Ind. Code § 5-14-3-4 and Ind. Code § 24-2-3-2, is exempt from public access and disclosure by Indiana law and shall be held confidential and protected from public access and disclosure by the Commission.

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

1. NIPSCO's requested fuel cost adjustment to be applicable to bills rendered during the billing cycles of May, June, and July 2014, as set forth in Finding No. 12 above is approved on an interim basis subject to refund as set out in Finding No. 14 above.

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

3. NIPSCO's request for approval of the option to transfer at market price to the GPR program the RECs obtained in conjunction with wind energy purchases under NIPSCO's wind purchase power agreements with Barton and Buffalo Ridge I Wind Farms and held in an account for NIPSCO's customers who pay the fuel adjustment clause shall be and is approved as set out in Finding No. 7 above.

4. NIPSCO 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 recover through the FAC, as discussed in Paragraph 7 (c) above. NIPSCO 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.

5. The information filed by NIPSCO in this Cause pursuant to NIPSCO's Motion for Protective Order is deemed confidential pursuant to Ind. Code § 5-14-3-4 and Ind. Code § 24-2-3-2, is exempt from public access and disclosure by Indiana law, and shall be held confidential and protected from public access and disclosure by the Commission.

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

**ATTERHOLT, MAYS, STEPHAN, WEBER, AND ZIEGNER CONCUR:**

**APPROVED:** APR 30 2014

**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**