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 NOVEMBER AND DECEMBER 2014 AND JANUARY 2015, 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 104** **APPROVED:** OCT 29 2014

ORDER OF THE COMMISSION

Presiding Officer:
Jeffery A. Earl, Administrative Law Judge

On July 31, 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 November and December 2014 and January 2015. NIPSCO also prefiled the direct testimony and exhibits of the following:

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

On August 5, 2014, the NIPSCO Industrial Group ("Industrial Group") filed a Petition to Intervene, which the Presiding Officer granted on August 18, 2014.

On September 4, 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 September 30, 2014, the Industrial Group filed direct testimony and exhibits of James R. Dauphinais, Managing Principal of Brubaker & Associates, Inc.

On October 3, 2014, NIPSCO filed the rebuttal testimony and exhibits of Ms. Cherven, Mr. Campbell, and Mr. Saffran.

The Commission held an evidentiary hearing at 9:30 a.m. on October 10, 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 of record, 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, plant and equipment within the State of Indiana used for the production, transmission, delivery, and furnishing of such 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 April, May and June 2014 averaged $0.034242per kWh.

4. Requested Fuel Cost Charge. NIPSCO seeks to change its fuel cost adjustment charge from the current charge of $0.009699 per kWh, for bills rendered during August, September, and October 2014 to a charge of $0.007886 per kWh for bills rendered during the billing cycles of November and December 2014, and January 2015.

The requested fuel cost adjustment includes a variance of $12,777,970 that was under-collected during April, May, and June 2014. NIPSCO's revised estimated monthly average cost of fuel to be recovered in this proceeding for the forecast period of October, November, and December 2014 is $45,794,102, and its estimated monthly average sales for that period are 1,392,983 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 (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 No. 2-A, shows that fuel costs for the 12 months ending June 30, 2014, were $127,343,861 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 June 30, 2014, were $118,054,574 above the levels approved in the 43969 Order. The Commission finds that NIPSCO's actual increase in fuel costs for the 12 months ending June 30, 2014, 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 was coal (86.96%) and the remainder was natural gas (13.04%) for the three months ended June 30, 2014.

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 six long-term contracts in the second quarter of 2014. Ms. Lowry said that NIPSCO would meet any remaining coal requirements through spot purchases.

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. Three 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 two long-term contracts have an annual market price reopener that will determine the contract coal price for the succeeding year of the contract.

Ms. Lowry testified that the delivered cost of coal for NIPSCO for the 12 months ending June 30, 2014, was $49.74 per ton or $2.464 per million Btu. The delivered coal cost for the reconciliation period (April, May, and June 2014) was $48.41 per ton or $2.447 per million Btu. NIPSCO purchased the following spot coal during the reconciliation period of April through June, 2014: 280,000 tons of ILB coal from Foresight Coal Sales to be used for the period of April 15, 2014 through September 30, 2014; 360,000 tons of Powder River Basin ("PRB") coal from Arch Coal Sales Company for the period of June 1, 2014 through September 30, 2014; 360,000 tons of PRB coal from Peabody COALSALES, LLC, for the period of June 1, 2014 through September 30, 2014. The average spot market price of coal (excluding transportation costs) during the reconciliation period was $13.31 per ton for PRB coal, $39.42 per ton for Illinois Basin ("ILB") coal, and $60.53 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 railroad congestion and shipment delays as a result of extreme winter weather conditions experienced during the first quarter of 2014. Railroad fluidity and velocity have not fully recovered since the first quarter, and all of NIPSCO's originating rail carriers continued to report locomotive and crew shortages throughout the reconciliation period. Additionally, the drawdown on coal inventory stockpiles throughout the industry during the first quarter led to increased demand for coal by other utilities during the reconciliation period, also contributing to the price increase on spot market coal. These factors have contributed to an increase in the spot market price of PRB coal, while spot prices for ILB and Pitt8 coal have remained relatively flat since last quarter. NIPSCO's delivered cost of coal during the reconciliation period decreased compared to the first quarter of 2014 from $51.17 per ton or $2.517 per million Btu to $48.41 per ton or $2.447 per million Btu. Although transportation costs slightly increased, decreased costs were due to the lower delivered cost of PRB coal (from $2.405/MMBtu to $2.325/MMBtu) and lower delivered cost of ILB coal (from $2.398/MMBtu to $2.312/MMBtu). Factors impacting the lower delivered costs of PRB and ILB coal include the discontinuance of freeze treatment costs, lower dust treatment costs, and price adjustments for coal quality. Fuel surcharges remained relatively flat during the reconciliation period.

Mr. Campbell stated there have not been any changes to NIPSCO's gas purchasing practices for NIPSCO's generation located on or off NIPSCO's gas distribution system. 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. Renewable Energy Credits ("RECs"). 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 net proceeds of $50,925 and no RECs were transferred to NIPSCO's Green Power Rider. NIPSCO has and will continue to pass the proceeds from the sale or transfer 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 stated there was not a sale of feed-in tariff RECs within the reconciliation period. NIPSCO is currently determining the most appropriate way to account for, reconcile, and market the RECs received from feed-in purchases. Currently, NIPSCO is in the process of setting up a test sale of feed-in tariff RECs in order to establish internal processes. Any future sale of RECs will be passed back through the FAC to include the net proceeds from this potential test sale.

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. Campbell testified 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 April, NIPSCO purchased 61 gas contracts and 330 power contracts. In May, NIPSCO purchased 35 gas contracts and 63 power contracts. In June, NIPSCO purchased 23 gas contracts and 21 power contracts. The execution of these contracts is consistent with NIPSCO's currently-effective electric hedging plan approved in Cause No. 44205 S2. The impact of the hedges entered into for the Electric Hedging Program for this proceeding was a gain of $1,004,388 during the reconciliation period. The net total impact of the hedging program in this proceeding was $998,133 during the reconciliation period. Broker fees represented 4% 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, 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 S2 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. Purchased Power Over The Benchmark. Mr. Campbell 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"). NIPSCO did not have any swap or virtual transactions during this FAC period. NIPSCO is seeking to recover 7,307.74 MWh of purchased power in April 2014, 11,151.19 MWh of purchased power in May 2014 and 16,282.55 MWh of purchased power in June 2014 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 reflect 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 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 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 ("MCCF") included in the actual cost of fuel for the months of April, May, and June 2014 was $6,309,031. In his prefiled direct testimony, Mr. Campbell testified that the estimate for MCCF was based on the average of actual MCCF incurred for the twelve

month period ending June 30, 2014. He stated NIPSCO has included an updated estimate of MCCF in the amount of $2,966,979 per month, which represents an approximate 10.6% increase from the last FAC filing. Mr. Campbell testified NIPSCO was evaluating three different methodologies to forecast this line item including: (1) the methodology proposed by Mr. Dauphinais in FAC 103 which consists of a three-year average of the MCCF by quarter; (2) a twenty-four-month rolling average of the MCCF; and (3) a high/low methodology where the high and low quarters are replaced with a three-year average of the MCCF for the applicable quarter. He stated these three methodologies will be tested against the existing twelve-month rolling average to determine if any produce less volatility for the MCCF line item. He testified that NIPSCO will continue to evaluate these methodologies and will share its analysis for the forecasting of the MCCF line item with stakeholders once the analysis is completed.

Mr. Dauphinais testified that NIPSCO, the OUCC, and the Industrial Group discussed alternative forecast methods. As a result of those discussions, he stated NIPSCO agreed to settle the issue by stipulating to the use of NIPSCO's proposed high/low method beginning in this current FAC proceeding, provided the OUCC does not object to the change. Even though the high/low method does not provide as much relief to FAC customers as the other alternative forecast methods, the Industrial Group is willing to accept the method in order to settle the issue. Mr. Dauphinais testified that the change will lower the FAC 104 MCCF forecast for October through December 2014 from $2,966,979 to $1,981,395 and lower NIPSCO's proposed FAC 104 fuel factor from 8.593 mills/kWh to 7.886 mills/kWh.

Mr. Dauphinais stated that the Industrial Group supports this stipulation for settlement purposes because it eliminates further delay in bringing relief to customers with respect to the MCCF forecast issue and addresses NIPSCO's expressed concerns with respect to the subjective nature of the Industrial Group's previous alternative forecast methods. Mr. Dauphinais also noted that the high/low method is the least aggressive of the four alternative forecast methods with respect to lowering the MCCF forecast for October through December 2014 from the value NIPSCO originally proposed in this proceeding. As a result, it is the least likely of the four alternatives to understate NIPSCO's future actual MCCF charges. For these reasons, Mr. Dauphinais recommends the Commission accept NIPSCO's proposed high/low forecast method for MCCF and implement the method in this current proceeding in place of NIPSCO's current rolling 12-month forecast method.

Mr. Campbell testified in rebuttal that all of the methods tend to have minimums, maximums, variance, and standard deviations consistent with each other, which indicates that over time the forecasts will tend to perform the same from an overall variance perspective. Additionally, Mr. Campbell testified that NIPSCO prefers to use forecast methodologies that reduce or eliminate any subjectivity. This is why NIPSCO is now proposing the high/low method of forecasting the MCCF line item. The method addresses both the high and low quarter of the 12-month rolling average by replacing those quarters with a 3-year average for that quarter. Mr. Campbell stated this is intended to soften the effects of any potential market anomaly while not completely disregarding its occurrence in the event the potential anomaly is the result of a new market trend.

Ms. Cherven testified in rebuttal that because there was sufficient time to recalculate the FAC 104 factor based on the new forecast method, NIPSCO and the Industrial Group agreed it is appropriate to adopt and incorporate the high/low forecasting methodology for purposes of this proceeding provided that the OUCC did not oppose the change. She testified her understanding was that the OUCC does not oppose the idea of changing the FAC 104 factor based on the new high/low forecasting methodology, but that they do reserve the right to review the calculations supporting the revised factor. Petitioner's Exhibit B, Revised Schedule 1 includes an updated $1,981,395/month estimate for the MCCF.

Based on the evidence, we conclude that the new high/low forecasting methodology for the MCCF is reasonable.

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 on 2 separate days for a total of 31 hours under Option C and 12 hours under Option D. The evidence shows that NIPSCO paid a total of $9,417,392 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 $2,354,348, through the FAC for the billing months of November and December 2014 and January 2015.

10. Estimation of Fuel Costs. NIPSCO's revised estimate for its prospective total average fuel costs for the months of October, November, and December 2014 will be $45,794,102/month.

Ms. Lowry testified that NIPSCO anticipates that its delivered coal cost during the forecast period of October, November, and December 2014 will be approximately $51.04 per ton or an estimated $2.486 per million Btu. The average spot market prices for calendar year 2015, excluding transportation, are currently $14.04 per ton for PRB coal, $40.69 per ton for ILB coal, and $61.23 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, and additional ILB and PRB spot coal to supplement the term purchases. However, if NIPSCO experiences a hot summer, which leads to increased coal burn, additional spot coal purchases may be needed to supplement term coal purchases. If spot coal purchases are required, the price of natural gas and rail transportation delivery issues may have an impact on the supply, demand, and cost of coal during the forecast period. NIPSCO anticipates that if spot purchases are required, spot coal prices will be slightly higher than its existing term coal

prices due to reduced inventories and higher demand for coal by other utilities. 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 has coal and transportation contracts in place for ILB coal for Bailly and R. M. Schahfer Generating Station, and for PRB and Pitt8 coal for Michigan City and R. M. Schahfer Generating Stations for 2014. Additional ILB spot coal was procured for the period of April through September 2014, and PRB spot coal was procured for the period of June through September 2014. NIPSCO's system inventory remains below target level as noted in FAC 103. NIPSCO continues to work with coal and transportation suppliers to increase inventory to target levels. This issue is not specific to NIPSCO, but continues to be an industry issue, as all major railroads are still experiencing congestion and delays related to locomotive constraints, crew shortages and weather impacts. Ms. Lowry stated this issue is not specific to NIPSCO, but continues to be an industry issue, as all major railroads are still experiencing congestion and delays related to locomotive constraints, crew shortages and weather impacts.

In our April 27, 2011 Order in Cause No. 38706-FAC 90 (at 6), 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 April, May, and June 2014 and incurred the following actual costs, resulting in a percent error calculated as follows:

Month	Estimated Fuel Cost	Actual Fuel Cost	Over (Under) Estimate
April	$0.032302/kWh	$0.033398/kWh	-3.28%
May	$0.030896/kWh	$0.035651/kWh	-13.34%
June	$0.030605/kWh	$0.033714/kWh	-9.22%
Weighted Average Estimating Error			**-8.77%**

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 FAC103. He stated that related to the forecast and the reduction in coal prices, the OUCC continues to review any coal or transportation price solicitations issued by NIPSCO.

Based on the evidence presented, including NIPSCO's estimate of its prospective fuel cost and its actual fuel costs for April, May, and June 2014, we find that NIPSCO's estimate of its prospective average fuel cost to be recovered during the November and December 2014 and January 2015 billing cycles is reasonable.

11. **Return Earned.** NIPSCO's exhibits demonstrate that for the 12 months ending June 30, 2014, Petitioner earned operating income including ECRM revenues of $197,540,543. This is less than NIPSCO's authorized amount of $221,672,865 approved in Cause No. 43969 plus NIPSCO's actual Environmental Cost Recovery Mechanism operating income during the 12 months ended June 30, 2014. 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, we find that during the 12 months ending June 30, 2014, NIPSCO did not earn a return more than that authorized in its last base rate case, as appropriately adjusted.

12. **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 June 30, 2014 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 June 30, 2014 greater than granted in its last general rate case; (4) the fuel cost adjustment for the quarter ending June 30, 2014 has been accurately applied; and (5) the figures used in the application for change in fuel cost adjustment for the quarter ending June 30, 2014 were supported by NIPSCO's books, records and source documents.

Mr. Guerrettaz testified that he and Mr. Eckert had a very detailed discussion with NIPSCO onsite about FTRs, ARRs, and Delta LMP. He stated the OUCC continues to work directly with NIPSCO to clarify and enhance the work papers provided in FAC filings and the large volume of data supporting the FAC filing and that NIPSCO has been very helpful in this area by providing personnel onsite for very detailed review of key audit areas.

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 among the highest in the State of Indiana and that NIPSCO's actual

monthly cost of fuel (mills/kWh) is among the highest in the State of Indiana; (6) NIPSCO's coal inventory is below normal target levels due to the recent extreme weather and NIPSCO is attempting to rebuild its inventory levels back to normal and that 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 NIPSCO disputes and has not paid until the dispute has been settled and NIPSCO pays the bill.

13. **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 $0.003058 per kWh and a recoverable interruptible factor of $0.000563 per kWh to be added to the revised estimated cost of fuel for bills rendered during the billing cycles of November and December 2014 and January 2015, in the amount of $0.032875 per kWh. This results in a fuel cost adjustment factor of $0.007886 per kWh, after subtracting from that cost the cost of fuel in NIPSCO's base rates and adjusting for applicable taxes. The evidence shows that a residential customer using 1,000 kWh per month will experience an overall decrease of $1.81 on his or her electric bill from the currently approved factor.

14. **Interim Rates.** 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. **Confidential Information.** On July 31, 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. By its August 18, 2014 docket entry, the Presiding Officer found such information to be preliminarily confidential, after which such information was submitted under seal by NIPSCO. 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 November and December 2014 and January 2015, as set forth in Finding No. 13 above is hereby 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 therein reflecting that such charges are applicable to the rate schedules reflected on the amendment.

3. 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 to 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.

4. 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.

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

STEPHAN, MAYS-MEDLEY, HUSTON, WEBER, AND ZIEGNER CONCUR:

APPROVED: OCT 29 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