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 MONTHS OF NOVEMBER AND DECEMBER 2012 AND JANUARY 2013, PURSUANT TO IND. CODE § 8-1-2-42 AND CAUSE NO. 43969 AND FOR APPROVAL OF RATEMAKING TREATMENT FOR THE COST OF WIND POWER PURCHASES PURSUANT TO CAUSE NO. 43393.	)	CAUSE NO. 38706 FAC 96 APPROVED: OCT 31 2012

ORDER OF THE COMMISSION

Presiding Officers:
Kari A.E. Bennett, Commissioner
Gregory R. Ellis, Chief Administrative Law Judge

On August 2, 2012, Northern Indiana Public Service Company ("NIPSCO" or "Petitioner") filed its petition for Commission approval of a fuel cost adjustment to be applicable for bills rendered by Petitioner during the billing months of November and December 2012 and January 2013. On that same day, Petitioner also prefiled its direct testimony and exhibits. NIPSCO Industrial Group ("Industrial Group") filed its Petition to Intervene on August 3, 2012, which was granted by the Presiding Officers in a Docket Entry dated August 17, 2012. On September 6, 2012, the Indiana Office of Utility Consumer Counselor ("OUCC") filed its report in this Cause along with its direct testimony. On September 21, 2012, Petitioner filed a Response to questions from the Presiding Officers.

Pursuant to public notice duly given and published as required by law, proof of which was incorporated into the record by reference and placed in the Commission's official file, an evidentiary hearing was held on September 25, 2012, at 2:00 p.m., in Room 224 of the PNC Center, 101 W. Washington Street, Indianapolis, Indiana. At the hearing, Petitioner, the OUCC, and the Industrial Group appeared by counsel. Petitioner and the OUCC offered their respective prefiled testimony and exhibits which were admitted into evidence without objection. No members of the general public appeared or sought to participate.

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

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

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

3. **Available Data on Actual Fuel Costs.** 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 (Pet.'s Ex. B, Sch. 1, Ln. 30). Petitioner's cost of fuel to generate electricity and the cost of fuel included in the cost of purchased electricity for the months of April, May and June 2012 averaged $0.029638 per kWh (Pet.'s Ex. B, Sch. 5, p. 4, Ln. 28).

4. **Requested Fuel Cost Charge.** Petitioner seeks to change its fuel cost adjustment charge from the current credit of $0.002980 per kWh (Pet.'s Ex. 1-C, Ln. 8) to a charge of $0.000491 per kWh (Pet.'s Ex. B, Sch. 1, Ln. 32), for all applicable bills rendered in November and December 2012 and January 2013 billing months. The requested fuel cost adjustment includes a variance of $4,074,039 (Pet.'s Ex. B, Sch. 1, Ln. 26) that was over-collected during April, May and June 2012. Petitioner's estimated monthly average cost of fuel to be recovered in this proceeding for the forecast period of October, November and December 2012, is $39,083,484 (Pet.'s Ex. B, Sch. 1, Ln. 24), and its estimated monthly average sales for that period are 1,317,949 MWh (Pet.'s Ex. B, Sch. 1, Ln. 11) .

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 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 June 30, 2012, were $45,038,076 (Pet.'s Ex. 2-A, p. 1, Ln. 15) above the levels approved in the 43969 Order, the last proceeding in which Petitioner's basic rates and charges for electric service were approved. Petitioner's Exhibit 2-A also shows that the total operating expenses excluding fuel for the twelve months ending June 30, 2012, were $46,785,894 above the levels approved in the 43969 Order. The Commission finds that Petitioner's actual increase in fuel costs for the twelve months ending June 30, 2012 have not been offset by actual decreases in other operating expenses.

7. **Efforts to Acquire Fuel and Generate or Purchase Power to Provide Electricity at the Lowest Reasonable Cost.** Petitioner's witness Strnatka testified that NIPSCO made every reasonable effort to acquire fuel so as to provide electricity to its retail customers at the lowest fuel cost reasonably possible. He testified that Petitioner's primary fuel for generation of electric energy is coal (72.37%) and the remainder by natural gas (27.63%) for the three months ended June 30, 2012 (Pet.'s Ex. 4, p. 2).

a. **Fuel Procurement.** With respect to NIPSCO's coal procurement process, Mr. Strnatka testified that NIPSCO considers several factors in purchasing coal, including the delivered price, the coal quality that is best suited for a particular generating unit, the sulfur content, and the economic and technical suitability of certain low cost fuels to be blended at NIPSCO's generating units to maintain the lowest reasonably possible "as-burned" fuel cost. Mr. Strnatka testified that NIPSCO also considers the availability, reliability and diversity of particular coal suppliers and coal transporters in its fuel procurement practices. He stated that NIPSCO has five (5) long term contracts with four (4) coal producers. 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 markets, producers and customers are reluctant to execute fixed price long term contracts without some type of market price adjustment mechanism and that maintaining a market price balance is beneficial to both parties. He explained that three (3) of NIPSCO's long term contracts have firm prices that increase each year as set out in the contract; one (1) 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 (1) 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 June 30, 2012, was $51.00 per ton or $2.554 per million Btu. The delivered coal cost for the reconciliation period (April, May and June 2012) was $52.12 per ton or $2.554 per million Btu. Mr. Strnatka stated NIPSCO did not make any spot purchases during the reconciliation period. He testified that the average market spot price of coal (excluding transportation costs) during the reconciliation period was $9.03 per ton for PRB coal, $41.10 per ton for Illinois Basin high sulfur coal, and $58.04 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, Mr. Strnatka testified that coal supply during the reconciliation period continued to be impacted by the mild weather, natural gas pricing and weak coal demand in both the domestic and international markets. Coal inventories grew but spot market pricing, particularly for Powder River Basin ("PRB") coal continued to slide, caused by lack of demand and oversupply. With NIPSCO's coal generation dispatch being unfavorably impacted by low natural gas prices, NIPSCO was not afforded buying opportunities to take advantage of the spot market for coal. NIPSCO fulfilled its limited coal requirements with strictly contract coal. He testified that NIPSCO's delivered cost of coal during the reconciliation period increased compared to the first quarter of 2012 from $50.62 per ton or $2.554 per million Btu to $52.12 per ton, but the average dollar per million Btu remained constant at $2.554 per million Btu. The static per million Btu delivered coal cost represents firm coal and transportation contract pricing in effect for 2012. Mr. Strnatka testified that fuel surcharges were 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 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. Therefore, the Commission finds NIPSCO's acquisition process is reasonable price.

b. <u>Renewable Energy Credits ("RECs")</u>. 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 RECs are utilized.

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 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.

We find that NIPSCO should continue to include in its quarterly FAC filings updates concerning its utilization of RECs associated with wind purchases being recovered through the authority granted in Cause No. 43393 and any other future renewable purchases.

c. Electric Hedging Program. Mr. Williamson 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. He testified that in April, NIPSCO purchased 2 gas contracts and 44 power contracts; in May, NIPSCO purchased 224 gas contracts and 44 power contracts; and in June, NIPSCO purchased 180 gas contracts and 20 power contracts. He stated the execution of these contracts is consistent with NIPSCO's most recently filed hedging plan. Mr. Williamson stated the impact of the hedges entered into for the Electric Hedging Program for this proceeding was a loss of $626,013 during the reconciliation period, plus broker fees and clearing exchange fees which totaled $5,770 during the reconciliation period, for a total impact of the hedging program in this proceeding of $631,783 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, and the transactions were all made in accordance with the Electric Hedging Program approved by the 43849 Order.

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, as hereinafter discussed. The Commission further finds that NIPSCO should continue to include testimony and evidence of its electric hedging costs, gains and/or losses resulting from its hedging transactions for which it is seeking recovery through the FAC in its quarterly FAC filings.

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 also testified that NIPSCO is seeking to recover 233,703.93 MWhs of purchased power in April; 66,912.25 MWhs of purchased power in May; and 4,737.58 MWhs of purchased power in June. He noted the amounts for April, May and June 2012 were in excess of the established Purchased Power Daily Benchmark. These purchases were made to supply jurisdictional load that offset available NIPSCO resources not dispatched by the Midwest Independent Transmission System Operator, Inc. ("MISO") or were otherwise eligible under the procedures outlined in the 43526 Order and are therefore recoverable. Mr. Michael Eckert who testified on behalf of the OUCC indicated that NIPSCO's testimony and workpapers reflect the 43526 Order regarding purchased power over the benchmark and that he agreed with NIPSCO'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, as hereinafter discussed.

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 Fuel Cost" included in the actual cost of fuel for the months of April, May and June 2012 was $5,510,162. (Pet.'s Ex. B, Sch. 5, p. 4, Ln. 19).

Mr. Williamson testified that effective June 12, 2012, MISO introduced a new charge type Demand Response Resource Uplift (RT_DRR_UPL). He explained that the existing and planned MISO market structures seek to provide opportunities for Demand Response Resources ("DRRs") to participate on a comparable basis as supply side resources. The basis of this structure came from Order 745 issued by the Federal Energy Regulatory Commission ("FERC") on March 15, 2011, which addressed an approach to compensate DRRs that helps ensure the competiveness of the organized wholesale market and remove barriers of DRRs to participate. As part of this Order, FERC determined that each ISO or RTO with a tariff that allows demand response to participate in its energy markets as a supply resource must pay any DRR that can balance supply and demand, the Locational Marginal Price ("LMP") for its energy reductions, after passing a FERC-approved net benefits test so that a determination can be made if a DRR is cost effective on a monthly basis. Mr. Williamson stated that the allocation method for these payments to DRRs must be made to wholesale buyers in the energy market area(s) where the demand response reduced the energy market price(s) at the time the DRR was committed or dispatched. MISO complied with this Order by establishing a monthly Net Benefit Price Threshold ("NBPT"). He explained that the NBPT is a market wide price threshold modeled to represent the Hourly LMP price in which DRR becomes beneficial to the market. The NBPT for June, 2012 was $25.10. If the LMP at the DRR node is less than the NBPT, the costs for all of the DRR energy reduction for that resource gets billed directly to the Load Serving Entity ("LSE") for that specific DRR through the Real Time ("RT") Asset Energy charge type, since it was energy that the LSE would have purchased if not for the DRR. Mr. Williamson testified that if the LMP at the DRR node is greater than the NBPT, then the cost is allocated through the new DRR Uplift charge type in the applicable Ancillary Services Reserve Zone which in effect the DRR is supplying reserves for this zone. If there are more DRR volumes than RT Energy Purchases, then the excess above the RT Energy Purchases is allocated to Revenue Neutrality Uplift under a new DRR Compensation bucket.

Mr. Williamson also explained why the Demand Response Resource Uplift is a "fuel-related" MISO charge (as opposed to a "non-fuel" MISO charge that would be recovered through NIPSCO's RTO Adjustment mechanism approved in Cause No. 44156). He testified that DRRs now have a mechanism in place that gives them the ability to make consumption decisions based on the value of energy consumed relative to the prevailing market price. This mechanism helps facilitate MISO in balancing supply and demand, and thereby helps produce just and reasonable energy prices. Customers who choose to respond will signal to MISO and the energy market their willingness to reduce demand on the grid which may result in reduced dispatch of higher-priced resources to satisfy load. The cost allocation to LSEs such as NIPSCO for this compensation to DRR will be settled through either RT Asset Energy or RT Demand Response Resource Uplift depending on whether the DRR LMP is above or below the NBPT. These costs are considered a fuel component which is similar to the recovery of RT Revenue Sufficiency Guarantee ("RSG") First Pass which is also considered a fuel component. RSG First Pass are charges resulting from compensation made to generation resources that are committed by MISO who are made whole when production and no load costs are below market prices. Based on the evidence, we find that the DRR Uplift charge is reasonably includable as a fuel cost for the purpose of establishing the fuel adjustment charge in this and future FAC filings.

In a September 19, 2012 Docket Entry, the Presiding Officers asked NIPSCO to explain why DRR Uplift charges should not be subject to a benchmark mechanism the same as or similar to the RSG First Pass charges. In its September 21, 2012 Response to that Docket Entry, NIPSCO explained that DRR Uplift charges should not be subject to a benchmark mechanism because the MISO tariff has already established and embedded a benchmark-type mechanism for allocating costs associated with compensating DRRs. NIPSCO also noted that the DRR Uplift charge is an extension of a FERC-approved tariff implementing demand response policy which is very different from the RSG charge that compensates generators for start-up and no load costs.

Based on the record evidence, we find that the DRR Uplift charge already has a "benchmark-type" mechanism embedded in the MISO tariff to ensure that the overall benefits of the reduced LMP that results from dispatching DRRs exceed the costs of dispatching and paying LMP to the resources that otherwise would have served the load. NIPSCO explained that FERC Order 745's approach to compensating DRRs provides just and reasonable rates by ensuring the competitiveness of the organized wholesale market and by removing barriers to participation. NIPSCO also explained that FERC introduced the concept of a net benefits test to determine whether a DRR is cost effective on a monthly basis. NIPSCO stated that MISO complied by introducing the NBPT. This serves to establish a market price level, above which DRRs become beneficial to the Real Time Energy and Operating Reserve Market. The NBPT is a mechanism that allows DRRs to make consumption decisions based on the value of energy consumed compared to a prevailing market price. NIPSCO stated that when the LMP is above the NBPT, the DRR, if cleared, will be compensated. DRR costs will then be allocated through the new DRR Uplift charge in the applicable reserve zone (i.e., the zone in which the DRR is supplying reserves). If the LMP is below the NBPT, a DRR could still be cleared, but there is no DRR Uplift Charge. Instead the DRR costs run through the RT Asset Energy Charge. The record evidence shows the NBPT is the mechanism that determines when DRR injections are cost-effective for the MISO market. We therefore find that it is not necessary or appropriate to subject the DRR Uplift Charges to a benchmark mechanism.

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 initiated interruptions on seven (7) separate days for a total of 49 hours under Option C and 23 hours under Option D. The evidence shows that NIPSCO paid a total of $9,296,677 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 $2,324,169, through the FAC for the billing months of November and December 2012 and January 2013 (Pet.'s Ex. B, Sch. 8).

10. **Estimation of Fuel Cost.** Petitioner estimated that its prospective total average fuel costs for the billing months of November and December 2012 and January 2013, will be $39,083,484 (Pet.'s Ex. B, Sch. 1, Ln. 24) on a monthly basis.

Mr. Strnatka testified that NIPSCO anticipates that its delivered coal cost during the forecast period of October, November and December 2012 will be approximately $48.95 per ton or $2.592 per million Btu. He noted that the delivered price could be influenced by the volatility in the diesel fuel market. Mr. Strnatka testified the average spot market prices for calendar year 2013 (which do not include cost of transportation) are currently $11.08 per ton for PRB coal, $44.03 per ton for Illinois Basin coal and $63.42 per ton for Pitt8 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.[1]

With respect to the factors NISPCO believes will impact the supply, demand, and cost of coal during the forecast period, Mr. Strnatka cited natural gas pricing. He testified that if natural gas fired generation continues to be competitive, and effectively displaces coal fired generation; coal pricing will remain very economical. Another factor that requires some attention is the ongoing cutbacks in domestic coal production and the financial impact on the coal producers. He stated that NIPSCO has transportation agreements in effect for 2012 with firm pricing (exclusive of fuel surcharges), so there will be no transportation price increases in the forecast period. The prices of West Texas Intermediate crude and highway diesel fuel have remained relatively stable. If this price stability continues, 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. The continuing challenge will be to manage NIPSCO's inventory. Currently, because of the increased demand for coal fired generation due to the recent excessive heat, NIPSCO's system inventory is only slightly above target level. He explained that railroads have annual minimum volume commitments in transportation agreements so it can allocate resources appropriately and incent customers to take a certain volume of coal or pay a specified dollar amount per ton for the shortfall. In NIPSCO's case, these annual minimum volume

1 PROMOD is NIPSCO's production cost modeling system. Pet.'s Ex. 3, p. 13.

commitments are negotiated based on the number of tons NIPSCO projects it needs for a particular coal. As NIPSCO has experienced in past transportation negotiations, achievable minimum volume commitments lead to more favorable transportation rates, and conversely, minimal or no minimum volume commitment, since the railroad can't plan its capacity, higher transportation rates. In years past, NIPSCO has met all of its minimum volume commitments in its rail transportation agreements, and its customers benefitted from the lower negotiated transportation rates. Mr. Strnatka testified that this year posed a challenge due to lower demand for energy experienced earlier this year, and low natural gas prices displacing coal fired generation. Liquidated damages could be incurred this year under at least one transport contract. However, he stated that NIPSCO is negotiating a verbal agreement with that railroad to be finalized in the next months to defer any shortfall tons to future years. Based on recent increased demand for coal fired generation, NIPSCO expects to meet all other railroads' minimum volume commitments, so NIPSCO will likely be able to avoid any payment for liquidated damages in 2012.

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) 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 April, May and June 2012 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	$0.029125/kWh	$0.028242/kWh	3.13%
May	$0.030053/kWh	$0.030838/kWh	-2.55%
June	$0.030027/kWh	$0.029793/kWh	0.79%
Weighted Average Estimating Error			**0.37%**

(Pet.'s Ex. B, Sch. 5, pp. 1-3, Lns. 28-29; Pet.'s Ex. B, Sch. 5, p. 4, Ln. 29).

OUCC Witness Gregory T. 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. (Public's Ex. 1, p. 6).

Based on NIPSCO's estimate of its prospective fuel cost and its actual fuel costs for April, May and June 2012, we find that NIPSCO's estimate of its prospective average fuel cost is reasonable for the billing months of November and December 2012 and January 2013.

11. **Return Earned.** Petitioner's exhibits demonstrate that for the twelve months ending June 30, 2012, Petitioner earned a return of $157,941,322 (Pet.'s Ex. 2-A, p. 1, Ln. 14b, Col. C). This is less than Petitioner's authorized amount of $190,182,331 (Pet.'s Ex. 2-A, p. 1, Ln. 14b, Col. B) approved in the 43969 Order plus NIPSCO's actual Environmental Cost Recovery Mechanism operating income during the period beginning with the 43969 Order through June 30, 2012 (Pet.'s Ex. 2-A, p. 1, Ln. 14a, Col. B). Therefore, during the twelve months ending June 30, 2012, the Commission finds NIPSCO did not earn a return more than that authorized in its last base rate case, as appropriately adjusted.

12. **Fuel Cost Adjustment Factor.** As we have set forth herein, 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 ($0.001030) per kWh (Pet.'s Ex. B, Sch. 1, Ln. 27) and a recoverable interruptible factor of $0.000588 per kWh (Pet.'s Ex. B, Sch. 1, Ln. 28) to be added to the estimated cost of fuel for the billing months of November and December 2012 and January 2013, in the amount of $0.029655 per kWh (Pet.'s Ex. B, Sch. 1, Ln. 25). This results in a fuel cost adjustment factor of $0.000491 per kWh (Pet.'s Ex. B, Sch. 1, Ln. 32), after subtracting from that cost the cost of fuel in NIPSCO's base rates and adjusting for applicable taxes. OUCC witness Mr. Eckert calculated that a residential customer using 1,000 kWh per month will experience an overall increase of $3.47 on his or her electric bill from the currently approved factor. Public's Ex. 2, p. 4.

13. **OUCC Report.** Mr. Gregory 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, 2012 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, 2012 greater than granted in its last general rate case; (4) the fuel cost adjustment for the quarter ending June 30, 2012 has been properly applied; and (5) the figures used in the application for change in fuel cost adjustment for the quarter ending June 30, 2012 were supported by NIPSCO's books and records and source documents.

Mr. Michael Eckert testified: (1) he reviewed NIPSCO's testimony and workpapers regarding the 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 RSG Distribution Amounts and Real Time RSG First Pass Distribution Amounts through the FAC pursuant to the Phase II Order; (4) 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 in the middle of the pack in the State of Indiana; (5) NIPSCO's coal inventory is just above target levels and the OUCC will continue to monitor and inform the Commission about NIPSCO's coal inventory in future FAC filings. Mr. Eckert also provided an update regarding NIPSCO's Electric Hedging Plan approved in the 43849 Order. Finally, Mr. Eckert testified that the OUCC recommends the Commission approve the implementation of NIPSCO's requested FAC factor.

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

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

1. Petitioner's requested fuel cost adjustment to be applicable to bills rendered in the months of November and December 2012 and January 2013, as set forth in Finding No. 12 above is hereby approved on an interim basis subject to refund as set out in Finding No. 14 above.

2. Petitioner shall continue to include in its quarterly FAC filings updates concerning its utilization of the RECs associated with the wind purchases being recovered through the FAC and testimony regarding any electric hedging transaction costs, gains and/or losses for which it is seeking recovery through the FAC, both as set out in Finding No. 7 above. NIPSCO shall also include in its quarterly FAC filings information as set out in Finding No. 10 above.

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

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

ATTERHOLT, BENNETT, LANDIS, MAYS AND ZIEGNER CONCUR:

APPROVED: OCT 31 2012

I hereby certify that the above is a true and correct copy of the Order as approved.

Brenda A. Howe

Brenda A. Howe
Secretary to the Commission