ORIGINAL

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY FOR APPROVAL OF A FUEL COST CHARGE AND CUSTOMER CREDIT ADJUSTMENT TO BE APPLICABLE IN THE MONTHS OF NOVEMBER AND DECEMBER 2009 AND JANUARY 2010, PURSUANT TO IC 8-1-2-42 AND CAUSE NO. 41746.	)	CAUSE NO. 38706 FAC 84 APPROVED: OCT 28 2009

BY THE COMMISSION:
David E. Ziegner, Commissioner
Aaron A. Schmoll, Administrative Law Judge

On August 10, 2009, Northern Indiana Public Service Company ("NIPSCO" or "Petitioner") filed its petition for Commission approval of a fuel cost adjustment to be applicable and made effective for bills rendered by Petitioner during the billing months of November and December 2009 and January 2010. Petitioner also prefiled its direct testimony and exhibits in support of its petition on August 10, 2009. NIPSCO Industrial Group ("NIPSCO-IG") and the City of Hammond, Indiana ("Hammond") filed Petitions to Intervene on August 11, 2009 and August 13, 2009, respectively, both of which were granted. On September 14, 2009, the Office of Utility Consumer Counselor ("OUCC") filed its report in this Cause and the Direct Testimony of Gregory T. Guerrettaz (Public's Exhibit No. 1) and Michael D. Eckert (Public's Exhibit No. 2). On October 2, 2009 NIPSCO filed supplemental testimony and revised exhibits, (Petitioner's Exhibit No. 7). On October 13, 2009, NIPSCO filed a response to a Commission docket entry issued October 9, 2009 (Petitioner's Exhibit No. 8).

Pursuant to public notice duly given and published as required by law, proof of which was incorporated into the record by reference and placed in the Commission's official file, a public hearing in this Cause was held on October 15, 2009, at 10:00 a.m., EST, in the National City Center, Room 222, 101 W. Washington Street, Indianapolis, Indiana. At the hearing Petitioner, the OUCC, NIPSCO-IG and Hammond appeared by counsel. Petitioner and OUCC offered their respective prefiled testimony and exhibits, which were admitted into evidence without objection. No other party or members of the general public appeared.

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

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

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

equipment within the State of Indiana used for the production, transmission, delivery and furnishing of such service to the public.

3. **Available Data on Actual Fuel Costs.** The Petitioner's cost of fuel to generate electricity and the cost of fuel included in the cost of purchased electricity in Petitioner's last base rate case order, approved, July 15, 1987, in Cause No. 38045, was $0.022556 per kWh (Revised Petitioner's Exhibit B, Schedule 1, Ln. 28). 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 2009 averaged $0.028770 per kWh (Petitioner's Exhibit B, Schedule 5, p. 4, Ln. 28).

4. **Requested Fuel Cost Charge.** Petitioner seeks to change its fuel cost adjustment charge from the current charge of $0.005682 per kWh (Petitioner's Exhibit 1-C, Ln. 6) to a charge of $0.003203 per kWh (Revised Petitioner's Exhibit B, Schedule 1, Ln. 30) for bills rendered in November and December, 2009 and January 2010 billing months. The requested fuel cost adjustment charge includes a variance of ($12,233,919) (Revised Petitioner's Exhibit B, Schedule 1, Ln. 25) that was over collected during April, May and June, 2009. In supplemental testimony, Ms. Cherven testified that the projected fuel cost charge was being modified due to the inclusion of a $1,670,750 refund ("Refund") on Revised Petitioner's Exhibit B Schedule 1, Line 25c. This proposed refund is defined in the terms of a settlement submitted for approval in Petitioner's FAC 80 S1. This revised fuel cost charge modified for the recovery of Indiana Utility Receipts Tax on Retail Sales and Adjusted Gross Income Tax, for the FAC period has decreased from $.003640 per kilowatt hour to $.003203 per kilowatt hour because of inclusion of the Refund. Petitioner's estimated monthly average cost of fuel to be recovered in this proceeding for the period November and December, 2009 and January 2010, is $37,937,535 (Revised Petitioner's Exhibit B, Schedule 1, Ln. 23), and its estimated monthly average sales for that period are 1,295,334 MWh (Revised Petitioner's Exhibit B, Schedule 1, Ln. 11).

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

(1) The electric utility has made every reasonable effort to acquire fuel and generate or purchase power or both so as to provide electricity to its retail customers at the lowest fuel cost reasonably possible;

(2) The actual increases in fuel cost through the latest month for which actual fuel costs are available since the last order of the Commission approving basic rates and charges of the electric utility have not been offset by actual decreases in other operating expenses;

(3) The fuel adjustment charge applied for will not result in the electric utility earning a return in excess of the return authorized by the Commission in the last proceeding in which the basic rates and charges of the electric utility were approved. However, subject to Ind. Code § 8-1-2-42.3, if the fuel charge applied for will result in the electric utility earning a return in excess of the return authorized by the Commission in the last proceeding in which basic rates and charges of the electric utility were approved, the fuel charge applied for will be reduced to the point where no such excess of return will be earned.

6. **Fuel Costs and Operating Expenses.** Petitioner's Exhibit 2-A, page 1, shows that fuel costs for the twelve months ending June 30, 2009, increased $166,387,601 (Petitioner's

Exhibit 2-A, p. 1, Ln. 22) from the pro forma level established in Petitioner's last base rate case, Cause No. 38045. Petitioner's Exhibit 2-A also shows that Petitioner's total operating expenses, excluding fuel in the twelve months ended June 30, 2009, exceeded by $197,632,450 (Petitioner's Exhibit 2-A, p. 1, Ln. 24) the pro forma level of other operating expenses determined pursuant to this Commission's Order in Cause No. 38045. The Commission finds that Petitioner's fuel costs have increased since its last general rate order and that the actual increases in fuel costs have not been offset by actual decreases in other operating expenses.

7. **Efforts to Acquire Fuel and Generate or Purchase Power to Provide Electricity at the Lowest Reasonable Cost.** Petitioner's witnesses described Petitioner's efforts to purchase fuel and generate and purchase power at the lowest cost reasonably possible. Witness Strnatka testified that Petitioner's primary fuel for generation of electric energy is coal (95.98% for the three months ended June 30, 2009). (Petitioner's Exhibit 4, p. 1).

In NIPSCO's FAC 83 proceeding, Witness Hasselbring testified concerning an outage at NIPSCO's Michigan City Unit 12 ("Unit 12"). Mr. Hasselbring stated that the coal ramp that brings coal into the main building for Unit 12 experienced a fire on January 8, 2009. Due to the damage from the fire, the coal conveyor and its structure had to be completely replaced. He stated that during the period of the structure rebuild, the station performed the annual planned maintenance outage on Unit 12 that was originally scheduled for later in the year. When the unit was not in the outage it was available to operate at full load on gas. Mr. Hasselbring stated that MISO did not call for the unit to run on gas during this time period. He stated that Unit 12 returned to operation on coal on April 18, 2009. By agreement of the parties in FAC 83, this issue was added to the topics for review in NIPSCO's FAC 80 S1.

On October 9, 2009, the Commission issued a docket entry noting that Petitioner's Exhibit 5-A indicated that Bailly Generating Station Unit 7 (Unit 7) entered a forced outage on June 21, 2009 which appeared to have continued through the remainder of the reporting period. The Commission asked if Unit 7 returned to service since the reporting period ended and if so, when. The Commission also asked Petitioner for details regarding the status of the Unit 7 outage investigation.

On October 13, 2009, NIPSCO responded to the Commission's docket entry and stated Unit 7 returned to service after the reporting period ended. Unit 7 was off-line for 16 days. The unit returned to service on July 8, 2009 at 7:51 AM. The unit was off-line due to a turbine bearing failure. Regarding the current performance of NIPSCO's steam generating units, NIPSCO provided a table, Exhibit A to its response to the Commission's docket entry, explaining the current performance of its steam generating units. In terms of the status of the investigation, NIPSCO has filed a Warranty Claim with the vendor, which is under review. NIPSCO submitted as Confidential Late-Filed Exhibit No. 9 a copy of the Warranty Claim.

Based on the evidence, but subject to further consideration in the FAC 80 S1 related to the Unit 12 outage, 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 in a reliable manner and at the lowest fuel cost reasonably possible, as hereinafter discussed.

8. **Midwest ISO Day 2 Energy Costs.** NIPSCO took into account in its forecast for this case the operational changes associated with the Midwest ISO Day 2 energy market, in accordance with the Commission's Orders in Cause Nos. 42685, 42962, 43471; and its FAC proceeding from FAC 68,. In Cause No. 42685, Petitioner was authorized to treat certain

defined Midwest ISO Day 2 market costs as a cost of fuel for purposes of the FAC process. In Cause Nos. 42962 and 43471, Petitioner was authorized to recover in FAC proceedings its Revenue Sufficiency Guarantee ("RSG") costs incurred after December 8, 2005. In the evidence submitted in support of its requested relief in this proceeding, Petitioner followed our orders in both Cause No. 42685 and Cause No. 43471. The Petitioner included in the FAC factor $2,706,943 as the total "MISO Components of Fuel Cost" for the months of April, May and June , 2009. (Petitioner's Exhibit B, Schedule 5, p. 4, Ln. 19).

9. **Changes in Charge Types as a Result of the Start of the Ancillary Services Market ("ASM").** In this proceeding, Mr. Crum stated that NIPSCO is requesting recovery of certain costs resulting from participation in the new Midwest ISO Energy and Operating Reserves Market ("MISO EOR") that includes ancillary services, which began operation on January 6, 2009. Mr. Crum testified that on June 30, 2009, the Commission issued its Phase II Order. The Commission found in the Phase II Order that the charge types listed below should be included in the cost of fuel for purposes of review in the FAC proceedings. As a result of the Phase II Order, NIPSCO is including the previously deferred amounts into its cost of fuel in this FAC proceeding:

- Day Ahead Regulation Amount
- Day Ahead Spinning Reserve Amount
- Day Ahead Supplemental Reserve Amount
- Contingency Reserve Deployment Failure Charge Amount
- Real Time Excessive Deficient Energy Deployment Charge Amount
- Real Time Regulation Amount
- Regulation Cost Distribution Amount
- Real Time Spinning Reserve Amount
- Spinning Reserve Cost Distribution Amount
- Real Time Supplemental Reserve Amount
- Supplemental Reserve Cost Distribution Amount
- Net Regulation Adjustment

Mr. Crum stated that since MISO launched its ASM on January 6, 2009, the ASM has generally functioned without any major issue. He stated that NIPSCO's generators have been following real time signals as directed by MISO with minimal issues. He noted that Day Ahead and Real Time market clearing prices (MCP) for Regulation, Spinning and Supplemental Reserves appear to be at reasonable levels consistent with market conditions.

Mr. Crum testified that the fuel costs requested for recovery in this proceeding also include net credits for the Midwest ISO's Contingency Reserve Deployment Failure Charge Uplift Amount ("Uplift Amount"), which is associated with the ASM. The Company has included a total credit of approximately $8,464 for this charge type in the current proceeding, which includes amounts for January 2009 through June 2009. This Uplift Amount is a separately identified component of the Midwest ISO's Revenue Neutrality Uplift Amount ("RNU".) Funds collected by the Midwest ISO from its charges to Generators for the Contingency Reserve Deployment Failure Charge Amount, which is one of the listed charges which the Commission approved as a cost of fuel in its ASM Phase II Order, are credited to Asset Owners via this Uplift Amount. The Commission's ASM Phase II Order did not specifically authorize the inclusion of this Uplift Amount in the cost of fuel for FAC proceedings by detailing the Uplift Amount in the

list of charges to be included as fuel in FAC proceedings on pages 39 and 40 of the Order. However, the Commission did order that RNU should continue to be treated for ratemaking purposes as it had been treated previously by the Joint Petitioners, "and as described in their testimony in this proceeding." (ASM Phase II Order, pages 40 and 41) All Joint Petitioners testified in Phase II of Cause No. 43426 that if the Midwest ISO separately identified the Uplift Amount subcomponent of RNU, it should be included as an offset to fuel cost and flowed through to customers in their respective FAC proceedings. Inclusion of the Uplift Amount in fuel is consistent with the previous treatment regarding a similar uplift credit for Uninstructed Deviation Revenues, for which the corresponding charge was also approved to be included as a cost of fuel.

Based upon the evidence presented, we find that NIPSCO's inclusion of the Energy and ASM charges and credits in its cost of fuel is consistent with our Phase I and Phase II Orders in Cause No. 43426. We further find that NIPSCO is authorized to include credits or charges for Contingency Reserve Deployment Failure Charge Uplift Amounts in this and future FAC proceedings.

10. Estimation of Fuel Cost. The Petitioner estimates that its prospective total average fuel costs for the billing months of November and December, 2009 and January 2010, will be $37,937,535 (Revised Petitioner's Exhibit B, Schedule 1, Ln. 23) on a monthly basis. Petitioner previously made the following forecasts of its fuel cost in April, May and June, 2009 and incurred the following actual costs, resulting in a percent error calculated as follows:

Month	Estimated Fuel Cost	Actual Fuel Cost	Percent Estimate Over (Under) Actual
April	$0.033323/kWh	$0.029287/kWh	13.78%
May	$0.031128/kWh	$0.027833/kWh	11.84%
June	$0.031696/kWh	$0.029152/kWh	8.73%
Weighted Average Error (%)			11.36%

Petitioners' Exhibit B, Schedule 5, pp. 1-3, Lns. 27-28; Petitioner's Exhibit B, Schedule 5, p. 4, Ln. 28. Crum p. 3-4.

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. Public's Exhibit No. 1, p. 7. Based on the evidence, we find that NIPSCO has made every reasonable effort to project its fuel related costs for the billing months of November and December 2009 and January 2010.

11. Purchased Pipeline Capacity. Karl E. Stanley, Executive Director, Energy Supply and Trading for NIPSCO submitted testimony to address NIPSCO's contracting for pipeline capacity on Midwestern Gas Transmission ("MGT") to serve the Sugar Creek Generating Station ("Sugar Creek"). Mr. Stanley explained that prior to the purchase of Sugar Creek, NIPSCO determined that it would need to hold sufficient MGT capacity to serve the plant in the future because MGT is the only pipeline connected to Sugar Creek. If NIPSCO did not enter into any transportation agreements with MGT, it would have to rely exclusively on an

energy manager to both secure and balance any supplies necessary to run the plant. In order to provide its own energy management services for the plant in the future, or at a minimum, have leverage when negotiating an energy management agreement, NIPSCO would need to hold MGT capacity. Consequently, NIPSCO entered into a Precedent Agreement ("Precedent Agreement") with MGT in February of 2008 that contained the following conditional precedents relating to NIPSCO's purchase of Sugar Creek: a) FERC approval of Sugar Creek's purchase; b) State Commission approval of such purchase; and c) NiSource Board of Directors' approval of the purchase. This "Precedent Agreement" reflected an expected in-service date that was tied to when the Rockies Express Pipeline ("REX") was expected to interconnect with MGT. The Precedent Agreement was expected to go into effect when REX was operationally interconnected with MGT. When it was signed, this operational start date was expected to be December 2008. While this interconnection was expected to be in-service by December of 2008, there were several construction delays on the REX pipeline that pushed back the in-service date to June 29, 2009. Mr. Stanley explained that NIPSCO signed the Precedent Agreement due to the open season timeline associated with the capacity necessary to serve Sugar Creek. This open season timeline was in advance of when NIPSCO would have made any decision regarding an energy manager for the plant.

Mr. Stanley testified that while NIPSCO was waiting for approval of the acquisition of Sugar Creek, NIPSCO learned that the seller of the plant (LS Power) was going to terminate its existing energy management agreement with Eagle Energy upon completion of the sale. Considering that Sugar Creek had been committed into the PJM market for two years starting in June 2008 and NIPSCO would not have any transportation agreements in place to serve the plant, it was necessary for NIPSCO to contract for an energy manager concurrent with the purchase so that the plant could be dispatched if called upon by PJM.

Mr. Stanley stated that NIPSCO sent out a Request for Proposals ("RFP") in April 2008 to three potential energy managers. After considering all three responses to the RFP, NIPSCO chose to retain Eagle Energy as the energy manager for the plant and signed a contract on May 29, 2008. While the MGT Precedent Agreement stated an expected in-service start date of December 2008, there was still some uncertainty around when the REX construction project would be completed. Mr. Stanley explained that NIPSCO wanted to build in some transition time from when energy management for the plant would be handled by a third party familiar with MGT and when energy management for the plant would be taken over by NIPSCO. Mr. Stanley testified that NIPSCO has released one-half of the pipeline capacity at cost to two different counterparties so one half of these charges have been fully mitigated. The other half of the capacity will be released to Eagle Energy at no cost, but Eagle Energy will have the opportunity to optimize this pipeline capacity and/or serve the plant. He stated that any margin that is achieved through this arrangement will be shared with NIPSCO who will pass any margin associated with this arrangement back to its customers as a credit to the future capacity cost. Mr. Stanley stated that the net capacity cost associated with the MGT capacity is reasonable.

On October 9, 2009, the Commission issued a docket entry asking for additional information regarding this issue. NIPSCO filed its response on October 13, 2009. No party objected to recovery of the cost of this capacity and based upon the evidence presented, including NIPSCO's response to the Commission's docket entry, the Commission finds that recovery of the net capacity cost associated with the MGT capacity contract is reasonable and should be approved.

12. **Return Earned.** Petitioner's Exhibit 2, containing Exhibit 2-A, demonstrates that for the twelve months ended June 30, 2009, Petitioner earned a jurisdictional return of $132,324,997 (Petitioner's Exhibit 2-A, p. 1, Ln. 21c, Col. F), a 5.32% rate of return (Petitioner's Exhibit 2-B, Ln. 9) on its jurisdictional rate base from Cause No. 38045. This amount included $13,323,480 (Petitioner's Exhibit 2-A, p. lB, Ln. 1) of opportunity off-system sales made from internally generated power, offset by fuel, purchased power costs, supporting variable costs and taxes for a net profit of $1,024,651, (Petitioner's Exhibit 2-A, p. l, Ln. 21b) in accord with the settlement agreement, referred to as the "August Agreement," approved by the Commission in Cause No. 42824 Order, Ordering Paragraph 1 (Aug. 23, 2006). As shown in Petitioner's Exhibit 2-A, the jurisdictional return authorized in Cause No. 38045, beginning in 1992 and thereafter, and adjusted for the Environmental Cost Recovery Mechanism return authorized in Cause No. 42150 ECR 13, pursuant to Ind. Code § 8-1-2-6.6 and 6.8, was $242,920,820 (Petitioner's Exhibit 2-A, p. 1, Ln. 21c, Col. B). Therefore, during the 12-month period ending June 30, 2009, NIPSCO did not earn a return more than that authorized in its last base rate case, as appropriately adjusted.

13. **Earnings Subject to Sharing.** Pursuant to the Commission's September 23, 2002 Order in Cause No. 41746 and the settling parties' acceptance of that Order, NIPSCO must share the over-earnings reported in each FAC. Petitioner's Exhibit 2-A reflects that for the 12-month period ended June 30, 2009, Petitioner has no such over-earnings.

14. **Fuel Cost Adjustment Factor.** As we have set forth herein, Petitioner has, subject to further consideration in FAC 80 S1, met the tests of Ind. Code § 8-1-2-42(d) for establishing a revised fuel cost charge. Petitioner's evidence presented a variance factor of $(0.003578) per kWh (including the Refund) (Revised Petitioner's Exhibit B, Schedule 1, Ln. 26), to be added to the estimated cost of fuel for the billing months of November and December, 2009 and January 2010, in the amount of $0.029288 per kWh (Revised Petitioner's Exhibit B, Schedule 1, Ln. 24), resulting in a fuel cost charge factor of $0.003203 per kWh (Revised Petitioner's Exhibit B, Schedule 1, Ln. 30), after subtracting from that cost the cost of fuel in NIPSCO's base rates and adjusting for applicable taxes. The average residential customer using 1,000 kwh per month will experience an overall decrease of $2.48 on his or her electric bill from the currently approved factor.

15. **Customer Credit Adjustment Factor.** Pursuant to our September 23, 2002 order in Cause No. 41746, Petitioner has set forth evidence of a Customer Credit Adjustment Factor percentage of 5.9235 (Petitioner's Exhibit D, p. 1, Ln. 10) to be applicable during the billing months of November and December, 2009 and January 2010. Petitioner's evidence showed the factor is calculated in accordance with the methodology prescribed in the September 23, 2002 order in Cause No. 41746.

16. **OUCC Report.** Mr. Guerrettaz testified: (1) NIPSCO has calculated the fuel cost element of the proposed fuel cost adjustment in conformity with the requirements of Ind. Code § 8-1-2-42; (2) NIPSCO has calculated a variance for the quarter ending September, 2009 in conformity with the requirement of Ind. Code § 8-1-2-42; (3) the level of operating income for the twelve month period ending June 30, 2009 is less than the level approved in NIPSCO's last rate case, Cause No. 38045, adjusted to reflect our order in Cause No. 42150 ECR 13; and (4) the fuel cost adjustment for the quarter ending June 30, 2009 has been properly applied.

17. **Purchased Power Costs Above Monthly Standard.** Mr. Crum described the Revised Benchmark that applies to Petitioner's purchased power transactions on and after

October 1, 2007. He stated that on January 30, 2008, a final order was issued in Cause No. 38706 FAC 71 S1, instituting a three tier Benchmark. Originally Tier 1 of the Benchmark utilized the costs of a Combined Cycle Gas Turbine ("CCGT") to establish the benchmark for determining the level of purchased power costs to be recovered by Petitioner. Effective December 1, 2008 Sugar Creek was dispatched into the Midwest ISO and Tier 1 was eliminated. When Tier 1 of the Benchmark was eliminated on December 1, 2008, Tier 2 of the Revised Benchmark became applicable to the first 500 MW of power purchases used to serve FAC load and became Tier 1. The current Tier 1 of the Revised Benchmark utilizes the costs of a Combustion Turbine ("CT") for determining the level of purchased power recovery. The current Tier 1 formula is almost the same as the recovery formula previously approved for Petitioner and other Indiana utilities using a benchmark recovery mechanism. Current Tier 2 permits, absent an act of God or a force majeure situation, Petitioner to recover 85% of its purchased power costs in excess of 500 MW. The applicable purchased power benchmark computed for April, 2009 is $46.13/MWh for the first 500; for May, 2009 is $41.13/MWh for the first 500 MWs; and for June, 2009 is $44.75/MWh for the first 500 MWs. Petitioner did not seek recovery of any purchased power costs in excess of the computed standard.

OUCC Witness Eckert confirmed Petitioner's purchased power benchmark calculations and confirmed $243,830 of purchase power as being non-recoverable in compliance with the Revised Benchmark.

Mr. Eckert stated that in FAC 80, the parties agreed to move issues regarding NIPSCO's requested recovery of hedging losses, NIPSCO's hedging policy, NIPSCO's stacking of power purchases between native load and off-system sales, and NIPSCO's calculation of purchased power costs under the Revised Benchmark to a sub-docket in Cause No. 38706 FAC 80 S1. Mr. Eckert stated that these same concerns are concerns in this Cause. Mr. Eckert recommended that Petitioner's FAC rates be made interim, subject to refunding, pending the final outcome of the FAC 80 S1. In supplemental testimony filed by Ms. Cherven, NIPSCO reported that all parties had reached resolution of the issues raised in the FAC 80 S1, and requested approval of the revised FAC 84 factors.

18. **Interim Rates.** Because we are unable to determine whether Petitioner will earn an excess return while this Order is in effect and because FAC 80 S1 remains pending, as discussed in Finding Nos. 4, 7, 14 and 17 above, the Commission finds that the rates approved herein should be interim rates, subject to refund.

19. **Confidential Information.** In response to the request by the Presiding Officers, on October 21, 2009, NIPSCO filed its *Motion for Protective Order* related to the Confidential Warranty Claim Letter identified and admitted at the hearing as Petitioner's Confidential Ex. 9 Late-Filed. In its Motion, NIPSCO requests a finding that certain information is confidential and indicates that certain information ("Confidential Information") that they intend to submit in this matter, contains trade secrets as that term is defined under Ind. Code 24-2-3-2. Information containing trade secrets is excepted from public disclosure under Ind. Code 5-14-3-4(a)(4).

The Commission finds that there is sufficient basis for a determination that the Confidential Information should be held as confidential by the Commission pursuant to Ind. Code 8-1-2-29 and Ind. Code 5-14-3. Subsequent to the hearing, NIPSCO provided a copy of the Confidential Warranty Claim letter to the Commission.

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

1. Petitioner's requested fuel cost charge to be applicable to bills rendered in the months of November and December, 2009 and January 2010, as set forth in Finding No. 14 above is hereby approved on an interim basis subject to refund as set out in Finding No. 18 above.

2. Petitioner's requested Customer Credit Adjustment Factor percentage to be applicable to bills rendered in the months of November and December, 2009 and January 2010, as set forth in Finding No. 15 above, is hereby approved.

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. NIPSCO is authorized to include credits or charges for Contingency Reserve Deployment Failure Charge Uplift Amounts as a cost of fuel in this and future FAC proceedings, as described in Finding No. 9 of this Order.

5. The Confidential Information addressed in Finding No. 19 above shall continue to be held as confidential.

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

HARDY, ATTERHOLT, GOLC, LANDIS, AND ZIEGNER CONCUR:

APPROVED: OCT 28 2009

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