STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY LLC PURSUANT TO IND. CODE §§ 8-1-2-42.7, 8-1-2-61 AND IND. CODE § 8-1-2.5-6 FOR (1) AUTHORITY TO MODIFY ITS RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE THROUGH A PHASE IN OF RATES; (2) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES, GENERAL RULES AND REGULATIONS, AND RIDERS; (3) APPROVAL OF REVISED COMMON AND ELECTRIC DEPRECIATION RATES APPLICABLE TO ITS ELECTRIC PLANT IN SERVICE; (4) APPROVAL OF NECESSARY AND APPROPRIATE ACCOUNTING RELIEF; AND (5) APPROVAL OF A NEW SERVICE STRUCTURE FOR INDUSTRIAL RATES.	)	CAUSE NO. 45159

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PETITIONER'S
EXHIBIT NO. Ad ntS 1
7-25-19 UC
DATE REPORTER

PETITIONER'S SUBMISSION OF
ADMINISTRATIVE NOTICE DOCUMENTS

Northern Indiana Public Service Company LLC ("NIPSCO"), by counsel, respectfully submits the following Indiana Utility Regulatory Commission Orders for which NIPSCO is seeking administrative notice pursuant to 170 IAC 1-1.1-21:

1. Order dated November 26, 2002 in Cause No. 42150;
2. Order dated October 29, 2014 in Cause No. 42150-ECR-24.
3. Order dated October 21, 2015 in Cause No. 42150-ECR-26.
4. Order dated April 20, 2016 in Cause No. 42150-ECR-27.
5. Order dated October 26, 2016 in Cause No. 42150-ECR-28.

6. Order dated April 26, 2017 in Cause No. 42150-ECR-29.
7. Order dated October 25, 2017 in Cause No. 42150-ECR-30.
8. Order dated April 25, 2018 in Cause No. 42150-ECR-31.
9. Order dated September 24, 2003 in Cause No. 42349;
10. Order dated August 25, 2010 in Cause No. 43526;
11. Order dated May 25, 2011 in Cause No. 43618;
12. Order dated December 16, 2015 in Cause No. 43618-DSM-9.
13. Order dated June 29, 2016 in Cause No. 43618-DSM-10.
14. Order dated February 22, 2017 in Cause No. 43618-DSM-11.
15. Order dated December 13, 2017 in Cause No. 43618-DSM-12.
16. Order dated December 21, 2011 in Cause No. 43969;
17. Phase III Order dated September 5, 2012 in Cause No. 44012;
18. Order dated December 19, 2012 in Cause No. 44198;
19. Order dated October 10, 2013 in Cause No. 44311;
20. Order dated January 29, 2014 in Cause No. 44340;
21. Order dated July 29, 2015 in Cause No. 44340-FMCA-3.
22. Order dated October 7, 2015 in Cause No. 44340-FMCA-3.
23. Order dated January 27, 2016 in Cause No. 44340-FMCA-4.
24. Order dated July 20, 2016 in Cause No. 44340-FMCA-5.
25. Order dated January 25, 2017 in Cause No. 44340-FMCA-6.
26. Order dated July 26, 2017 in Cause No. 44340-FMCA-7.
27. Order dated January 31, 2018 in Cause No. 44340-FMCA-8.
28. Order dated July 25, 2018 in Cause No. 44340-FMCA-9.
29. Order dated February 17, 2014 in Cause No. 44370;

30. Order dated February 17, 2014 in Cause No. 44371;

31. Order dated May 7, 2014 in Cause No. 44371;

32. Order dated September 23, 2015 in Consolidated Cause Nos. 44370 and 44371;

33. Order dated December 16, 2015 in Consolidated Cause Nos. 44370 and 44371;

34. Order dated December 30, 2015 in Cause No. 44634;

35. Order dated July 18, 2016 in Cause No. 44688;

36. Order dated July 12, 2016 in Cause No. 44733;

37. Order dated January 25, 2017 in Cause No. 44733-TDSIC-1;

38. Order dated April 19, 2017 in Cause No. 44733-TDSIC-1-S1

39. Order dated October 31, 2017 in Cause No. 44733-TDSIC-2;

40. Order dated May 30, 2018 in Cause No. 44733-TDSIC-3;

41. Order dated September 26, 2018 in Cause No. 44733-TDSIC-3;

42. Order dated December 13, 2017 in Cause No. 44872;

43. Order dated July 12, 2017 in Cause No. 44889;

44. Order dated September 12, 2018 in Cause No. 45011;

45. Order dated January 3, 2018 in Cause No. 45032;

46. Order dated February 16, 2018 in Cause No. 45032

In addition, NIPSCO requests administrative notice to be taken of its 2018 Integrated Resource Plan ("IRP"), a portion of which is subject to a currently pending request for a preliminary determination of confidentiality by the Commission and is the subject of NIPSCO's First Motion for Protective Order.

Not Granted.

Copies of these orders (as well as the public version of the 2018 IRP) are being filed contemporaneous with this Petition.

Respectfully submitted:

Claudia J. Earls (No. 8468-49)
NiSource Corporate Services - Legal
150 West Market Street, Suite 600
Indianapolis, Indiana 46204
Phone: (317) 684-4923
Fax: (317) 684-4918
Email: cjearls@nisource.com

Attorney for Petitioner
Northern Indiana Public Service Company LLC

CERTIFICATE OF SERVICE

The undersigned hereby certifies that the foregoing was served by email transmission upon the following:

William Fine
Abby R. Gray
Randall C. Helmen
Indiana Office of Utility Consumer Counselor
115 W. Washington Street, Suite 1500 South
Indianapolis, Indiana 46204
wfine@oucc.in.gov
agray@oucc.in.gov
rhelmen@oucc.in.gov
infomgt@oucc.in.gov

A courtesy copy has also been provided by email transmission upon the following:

Todd A. Richardson
Joseph P. Rompala
Lewis & Kappes, P.C.
One American Square, Suite 2500
Indianapolis, Indiana 46282
trichardson@lewis-kappes.com
jrompala@lewis-kappes.com

Bette J. Dodd
Lewis & Kappes, P.C.
One American Square, Suite 2500
Indianapolis, Indiana 46282
bdodd@lewis-kappes.com

Nikki G. Shoultz
Kristina K. Wheeler
Bose McKinney & Evans LLP
111 Monument Circle, Suite 2700
Indianapolis, Indiana 46204
nshoultz@boselaw.com
kwheeler@boselaw.com

Jennifer A. Washburn
Citizens Action Coalition
603 East Washington Street, Suite 502
Indianapolis, Indiana 46204
jwashburn@citact.org

Robert M. Glennon
Robert Glennon & Assoc., P.C.
3697 N. Co. Rd. 500 E
Danville, Indiana 46122
glennon@iquest.net

James W. Brew
Stone Mattheis Xenopoulos & Brew, PC
1025 Thomas Jefferson St., N.W.
8th Floor, West Tower
Washington, DC 20007
jbrew@smxblaw.com

Dated this 31st day of October, 2018.

Claudia J. Earls

ORIGINAL

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE CONSTRUCTION OF CLEAN COAL TECHNOLOGY UNDER IND. CODE § 8-1-8.7, et. seq., APPROVAL OF THE USE OF QUALIFIED POLLUTION CONTROL PROPERTY UNDER IND. CODE § 8-1-2-6.6 AND AUTHORIZATION TO DEFER AND AMORTIZE DEPRECIATION AND OPERATION AND MAINTENANCE EXPENSES ASSOCIATED WITH CLEAN COAL TECHNOLOGY.	)	CAUSE NO. 42150 APPROVED: NOV 2 6 2002

BY THE COMMISSION:
Judith G. Ripley, Commissioner
Scott R. Storms, Chief Administrative Law Judge

On January 4, 2002, Northern Indiana Public Service Company ("Petitioner", "Company" or "NIPSCO") petitioned the Indiana Utility Regulatory Commission ("Commission") for: (a) a certificate, under Ind. Code § 8-1-8.7, that public convenience and necessity will be served by its proposed use of clean coal technology ("CCT") to comply with the federal NOx State Implementation Plan Call ("SIP" or "SIP Call") and related Indiana NOx SIP Call which requires NIPSCO to achieve a level of 0.15 lb./mmBtu at its electric generating plants by May 31, 2004; (b) approval of the anticipated use of the CCT as qualified pollution control property ("QPCP") under IC § 8-1-2-6.6; and, (c) for ratemaking treatment of the capital costs of, and operation and maintenance ("O&M") and depreciation expenses connected with, such QPCP.[1]

Pursuant to notice published as required by law, proof of which was incorporated into the record, an Evidentiary Hearing was held in this matter on August 13 and 26, 2002, in Room E-306 of Indiana Government Center South, Indianapolis, Indiana. At the Evidentiary Hearing, NIPSCO presented its case in chief, consisting of testimony and exhibits of David J. Vajda, Robert D. Greneman, John M. Ross, Cathy E. Hodges and Robert D. Cook in support of NIPSCO's petition and a Settlement Agreement ("Settlement Agreement") submitted by the Petitioner and the Indiana Office of the Utility Consumer Counselor ("OUCC"). The Intervenors, LaPorte County and the City of Michigan City, presented the testimony of Reed W.

[1] The terms "CCT" and "QPCP" refer to the same facilities and are used interchangeably in this order.

Cearley. All pre-filed testimony and exhibits, including the Settlement Agreement, were admitted into evidence, without objection. NIPSCO also filed written responses to questions from the Intervenors directed to NIPSCO witness Cook, which were aggregated in Petitioner's Exhibit E-3 and admitted into evidence, without objection.[2]

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

1. **Notice and Jurisdiction**. Proper legal notice of the hearing in this case was given and published by the Commission as required by law. Petitioner is a public utility within the meaning of the Public Service Commission Act, as amended, IC 8-1-2, and is subject to the jurisdiction of the Commission, in the manner and to the extent provided by the laws of the State of Indiana. The Commission has jurisdiction over Petitioner and the subject matter of this case.

2. **Petitioner's Characteristics and Generating System**. Petitioner is a public utility organized and existing under the laws of the State of Indiana, with its principal office at 801 E. 86th Street, Merrillville, Indiana 46410. NIPSCO owns and operates property and equipment used for the production, transmission, delivery and furnishing of electric service to the public in Indiana, including four generating stations that have coal-fired generating units. Pet. Ex. A-2.

3. **Relief Requested**. In its Petition, NIPSCO requests that the Commission grant the Company a Certificate of Public Convenience and Necessity for its use of CCT, pursuant to IC § 8-1-8.7-3, to achieve compliance with the NOx SIP Call. Pet. Ex. A-1, p. 2. NIPSCO also requests that the Commission conduct ongoing review of such Compliance Plan, under IC § 8-1-8.7-7. Pet. Ex. D, pp. 7-8. NIPSCO further requests a determination that the CCT constitutes QPCP under IC § 8-1-2-6.6 and 6.8 and that the Commission approve certain ratemaking and accounting treatments with respect to costs incurred during construction and operation of the QPCP, including: (a) CWIP ratemaking treatment for the capital costs of the QPCP during construction and until the facilities are determined to be used and useful in a base rate case; (b) an allowance for funds used during construction ("AFUDC") prior to such CWIP ratemaking treatment for such capital costs; (c) authority to recover depreciation, and O&M expenses connected with the QPCP once it goes into service; and (d) the exclusion from NIPSCO's Fuel Adjustment Clause ("FAC") earnings cap calculation any return realized on its QPCP prior to its next base rate case. Pet. Ex. A-1, p. 2 and A-4, pp. 1-2.

4. **Commission Analysis, Findings and Conclusions**. As part of our review in this matter we will first consider the requirements of IC §§ 8-1-8.7-1, 8-1-8.7-3 and 8-1-8.7-7, and

[2] On August 12, 2002, NIPSCO moved to amend its petition to reference IC § 8-1-2-6.8, as applicable to the proceeding. That statute was added by the General Assembly in 2002, by PL 159-2002, after the filing of NIPSCO's petition, and applies to QPCP construction beginning after March 31, 2002. There was no opposition expressed to such amendment, and the terms of the amendment are reflected in the Settlement Agreement.

will then undertake an analysis of the requirements of IC § 8-1-8.7-4. We shall also review the issues presented with respect to NIPSCO's request for classification of QPCP under IC §§ 8-1-2.6.6 and 6.8, and approval of certain ratemaking and accounting treatments with respect to costs incurred during construction and operation of the QPCP, including: (a) recovery of a return at rates computed in accord with 170 IAC 4-6-1 *et. seq.*, on NIPSCO's investment in QPCP, to be applicable until the Commission makes a determination in a future base rate case regarding the use and usefulness of such facilities, under IC §§ 8-1-2-6.6 and 6.8 and 170 IAC 4-6-9; (b) authorization for NIPSCO to implement an Environmental Cost Recovery Mechanism ("ECRM") to realize such return, and; (c) authorization for NIPSCO to implement an Environmental Expense Recovery Mechanism ("EERM") to recover its depreciation and O&M expense once the QPCP is in service.

a. IC §§ 8-1-8.7-1 and 8-1-8.7-3 Review and Findings. IC § 8-1-8.7-3 requires that before a utility may use clean coal technology at its generating plants, it must obtain from the Commission a certificate stating that the public convenience and necessity will be served by the use of such clean coal technology, the latter being defined in IC § 8-1-8.7-1 as technology that reduces airborne emissions of sulfur or nitrogen based pollutants associated with the combustion of coal that either: (a) was not in general use at the same or greater scale in new or existing facilities in the United States as of January 1, 1989; or (b) has been selected for funding by the U.S. Department of Energy ("DOE") under its Innovative Clean Coal Technology program and was finally approved for such funding on or after January 1, 1989. IC § 8-1-8.7-7 provides that an applicant for a clean coal technology certificate may elect to undergo ongoing review of its construction and construction costs, in which case the utility must periodically submit progress reports and cost estimate revisions to the Commission.

Petitioner's witness Robert D. Cook described NIPSCO's proposed use of CCT and its strategy to reduce NOx emissions. Pet. Ex. E-1. Mr. Cook testified that the Selective Catalytic Reduction ("SCR") projects and the Over Fire Air and Low NOx Burner projects included in Petitioner's Compliance Plan will reduce airborne emissions of nitrogen based pollutants associated with the combustion of coal to levels required by the NOx SIP Call. Id., pp. 6-7. Mr. Cook indicated that this CCT is more efficient than conventional technologies in general commercial use as of January 1, 1989, and indicated that NIPSCO could not achieve compliance with the NOx emission standards with conventional technologies. Id., p. 13. Accordingly, based on the testimony presented in this Cause we find that the proposed SCR, Over Fire Air and Low NOx Burner projects constitute clean coal technology projects as defined in IC § 8-1-8.7-1.

1. The costs of the clean coal technology compared to conventional emission reduction facilities. Mr. Ross described how Petitioner began, in the early 1990's, to analyze methods for achieving compliance with the Clean Air Act Amendments of 1990. Mr. Ross testified that based on the NOx reduction provisions contained in the Clean Air Act Amendments of 1990, conventional technologies were not sufficient to allow NIPSCO to achieve compliance with the NOx SIP Call. Pet. Ex. C-1, p. 7. Accordingly, the members of an internal work group formed by the Petitioner, with the assistance of outside consultant, Black & Veatch, developed a Phase III NOx compliance study ("Phase III Study") issued in September 1999. This compliance study provided the basis for the Petitioner to develop its Compliance Plan ("Compliance Plan")

for Indiana's NOx SIP Call requirements, which were approved by the United States Environmental Protection Agency ("EPA") on November 8, 2001. Id.

Petitioner identified and evaluated the technologies that were available for reducing NOx emissions and concluded that the most economical technologies were SCR systems, Over Fire Air Systems and Low NOx Burners. Pet. Ex. E-1, pp. 5-6. Based on the foregoing, the Petitioner developed a plan that would allow it to integrate the new technologies while developing a multi-pollutant compliance plan. The estimated cost of NIPSCO's compliance plan is approximately $235 million dollars. Mr. Cook testified that Petitioner considered another technology, Selective Noncatalytic Reduction systems, but that technology was not capable of reducing the NOx emissions by a sufficient amount. Pet. Ex. E-1, p. 7.

Based on this evidence, we find that achievement of the NOx SIP Call standard could not be achieved through conventional technologies. Accordingly, we find the CCT selected by NIPSCO, and its estimated cost, appear reasonable and should be approved.

2. Whether the proposed CCT will extend the useful life of NIPSCO existing generating facilities and Costs of Retirement of existing units. Mr. Cook testified that without the proposed CCT, Petitioner could not continue to operate its coal-fired generating facilities beyond May 31, 2004, and comply with the new NOx emission standard. Id., p. 13. Accordingly, the evidence establishes that the installation of SCRs, Low NOx Burners and Over Fire Air Systems will allow for the continued utilization of existing generating units that otherwise would not be possible and we find that the Petitioner's proposal extends the useful life and the value of these facilities.

3. Potential reduction of NOx to be achieved by the proposed CCT compared with conventional equipment. Mr. Cook testified that the reduction of NOx emissions by the conventional technology in general use on January 1, 1989, would not be sufficient to bring the Petitioner into compliance with the NOx SIP Call. Id. Mr. Cook testified that the technologies included in Petitioner's Compliance Plan are more efficient and will allow NIPSCO to meet the new standards. The SCRs included in Petitioner's Compliance Plan are designed to remove at least 85 percent of the NOx emissions by a chemical process that reduces NOx to nitrogen and water. Mr. Cook testified that the Over Fire Air System and Low NOx Burner technologies are capable of reducing NOx emissions by 30 to 50 percent. Mr. Cook explained that Petitioner's Compliance Plan consists of the use of: (a) SCRs at Michigan City Unit 12, Schahfer Unit 14, and Bailly Units 7 and 8; and (b) Low NOx Burners and Over Fire Air Systems at Schahfer Units 17 and 18. Id., pp. 6-7. Mr. Cook also explained how the SCRs, Low NOx Burners and Over Fire Air Systems qualify as clean coal technology under IC § 8-1-8.7-1. Based on this testimony, we find that the reduction of NOx emissions by conventional technology would be insufficient to bring Petitioner into compliance with the NOx SIP Call and that the Petitioner's proposed CCT will enable NIPSCO to meet the new standard within the applicable time limits established by law.

4. Federal and State standards and likelihood of success. Mr. Ross described the new federal and state environmental standards concerning the reduction of NOx emissions that are applicable to Petitioner. Pet. Ex. C-1, pp. 3-5. He detailed the history of the federal and state NOx SIP Calls and the allocation of allowances to each generating unit, and how the Petitioner's Compliance Plan is designed to meet the May 31, 2004, NOx emissions reduction deadline. Based on the testimony presented in this Cause, we find that the Petitioner's Compliance Plan appears to be reasonable, meets the criteria set forth in this section, and should be approved.

5. Dispatching Priority. Mr. Cook testified that the dispatching priority of NIPSCO's generating units would not be changed unless it was necessary to achieve compliance with the emission standard. Id., p. 14. The Commission finds that this approach to dispatching priority appears to be reasonable, appropriate, and in compliance with Indiana law.

b. IC § 8-1-8.7-4 Review. IC § 8-1-8.7-4 requires that as a condition for receiving the certificate required under IC 8-1-8.7-3 of this chapter, an applicant must file an estimate of the cost of constructing, implementing, and using clean coal technology and supportive technical information. Based on the information provided, and following public hearing, the Commission must determine whether the public convenience and necessity will be served by the construction, implementation, and use of clean coal technology; if the estimated cost should be approved; and, determine whether the facility utilizes and will continue to utilize Indiana coal as its primary fuel source or is justified, because of economic considerations or governmental requirements, in utilizing non-Indiana coal after the technology is in place.[3]

Pursuant to the requirements set forth in IC § 8-1-8.7-4, and based on our review of the evidence presented in this Cause, the Commission hereby finds as follows:

1. Public Convenience and Necessity Review Regarding the Construction, Implementation and Use of Clean Coal Technology. Petitioner has adequately demonstrated the need for its NOx Compliance Plan projects. Various federal and state environmental requirements have coalesced to require Petitioner to reduce the NOx emissions at its generating plants. Petitioner has demonstrated that its proposed approach, the timing of its projects and its choice of projects are reasonable and necessary in order for Petitioner to fully comply with federal and state law. Petitioner considered all currently available options for NOx emission reduction. Petitioner demonstrated that SCRs are necessary because only they can reduce NOx emissions to levels at or below the SIP Call system average requirement of 0.15 lb/mmBtu. Petitioner's NOx Compliance Plan has built in flexibility that will allow it to adapt to possibly

[3] IC § 8-1-8.7-4 and 170 IAC 4-6-4 indicate that the utility must show it will continue to use Indiana coal as its primary fuel or is justified in not doing so. However, as we noted in Cause No. 41864 (*Ind. Util. Reg. Comm'n,* Aug. 29, 2001), the Indiana Court of Appeals has declared that the portion of IC § 8-1-2-6.6 relating to Indiana coal is an unconstitutional violation of the Commerce Clause. Thus, although Petitioner's evidence indicates that NIPSCO's proposed CCT will permit the continued use of Midwestern (including Indiana) coal at Bailly Units 7 and 8 and Schahfer Units 17 and 18, as their primary fuel source, we will not use that as a prerequisite for Petitioner to receive a certificate of clean coal technology, or to obtain QPCP status.

lower cost measures if a vibrant emission allowance market develops, or new technology emerges. We find that Petitioner has demonstrated that its proposed NOx Compliance Plan is a reasonable and necessary means of meeting required federal and state environmental mandates.

2. Reasonableness of Estimated Costs. Petitioner's witness Cook testified that the current estimated cost of the Compliance Plan, approximately $235 million dollars, represents a decrease since the Company filed its petition in this cause, due to a reduction in the planned number of SCRs in the Compliance Plan from five to four. Id., pp. 14-15. Mr. Cook made clear that NIPSCO's Compliance Plan is not static and may well change and evolve during the course of the three-year implementation period, as NIPSCO may take advantage of new technological developments not a part of the current plan. Pet. Ex. E, p. 9. Indeed, the possibility of such revisions contributed to NIPSCO's decision that its Compliance Plan should be reviewed and subject to revision annually, as permitted by IC § 8-1-8.7.7. Mr. Cook testified that Petitioner's NOx compliance strategy could also accommodate the purchase of emission allowances and stated that these allowances could be an economic and efficient way for NIPSCO to comply with the SIP Call, by either permitting the Company to delay construction or by constituting a compliance strategy, in and of itself, for specific units. Id., p. 12.

Based on our review of the evidence, we find that the Petitioner has adequately demonstrated the need for implementing its NOx Compliance Plan. The Petitioner has demonstrated that its proposed approach, the timing of its projects, and its choice of technologies are reasonable and necessary in order for Petitioner to comply environmental mandates set forth in federal and state law. The evidence shows that Petitioner considered currently available options for NOx emission reductions and concluded that the use of its proposed CCT is necessary for it to comply with the NOx SIP Call. The testimony presented in this matter also demonstrates that the SCRs, Over Fire Air Systems, and Low NOx Burner systems are necessary, to reduce NOx emissions at NIPSCO's plants to levels at or below the SIP Call requirement of 0.15 lb/mmBtu. Petitioner's NOx Compliance Plan also appears to contain flexibility that will allow it to adapt to possibly lower cost measures such as emission allowances or new technology. Accordingly, the Commission finds that the Petitioner has demonstrated that its proposed NOx Compliance Plan is reasonable and necessary for it to achieve compliance with required federal and state environmental mandates and should be approved.

Based on the foregoing, we find that the public convenience and necessity will be served by the construction, implementation and use of Petitioner's proposed CCT and the execution of its Compliance Plan. The estimated costs of these projects are approved, and that Petitioner should be granted a Certificate of Public Convenience and Necessity for the construction and operation of these projects.

c. **Ongoing Review Under I.C. § 8-1-8.7-7**. Petitioner has requested ongoing review of the construction of its CCT projects. Under IC § 8-1-8.7-7, the utility is to submit, at least annually, unless the utility and the Commission agree otherwise, a progress report detailing any revisions in the cost estimates or the planned construction. The Commission must hold a hearing before it may approve or deny a proposed increase in the cost estimate for the implementation, construction, or use of the clean coal technology. If the Commission approves the construction and the costs, that approval forecloses subsequent challenges to the inclusion of those costs in the utility's rate base on the basis of excessive cost, inadequate quality control, or inability to employ the technology.

Mr. Cook indicated that Petitioner will continue to optimize its NOx Compliance Plan and will update the plan as revised standards or costs become known to the Company. Id., p. 8. The ongoing review procedure will provide Petitioner assurance that its costs will be recoverable, and will provide the Commission and interested parties the opportunity to review the projects as construction proceeds.

We find that Petitioner's request for ongoing review should be approved. Petitioner may make its ongoing review filing under the clean coal technology statute in conjunction with its ECRM semi-annual rate adjustment filings addressed in the Settlement Agreement. However, the ECRM semi-annual proceedings must be filed with the Commission, and the Commission must hold a hearing prior to approving or denying a proposed increase in the cost estimate for the implementation, construction, or use of the clean coal technology. Accordingly, based on the evidence presented in this Cause, we hereby find that the Petitioner's request for ongoing review of the construction of its clean coal technology projects, under IC § 8-1-8.7-7, should be granted consistent with our findings herein.

6. **QPCP Review, CWIP Statute and Administrative Rules and Accounting Treatments**. IC §§ 8-1-2-12 and 14 outline the statutory authority for the Commission to review the accounting practices of an Indiana public utility. 170 IAC 4-6-4 provides that the Commission shall approve the use of QPCP if it consists of one or more air pollution control devices; meets the applicable state and federal requirements; is designed to accommodate the burning of coal; and, if the estimated costs of construction and installation are reasonable. Under IC §§ 8-1-2-6.6 and 6.8 and 170 IAC 4-6-5, if pollution control equipment is found to be QPCP, the utility is allowed to add the value of the QPCP to the value of the utility's property for ratemaking purposes. Under 170 IAC 4-6-9, the CWIP ratemaking treatment is available for QPCP that has been under construction for not less than six months.

NIPSCO requests that we find that its NOx Compliance Plan projects are QPCP. Petitioner has adequately demonstrated that its NOx Compliance Plan consists of clean coal technology designed to meet applicable federal and state environmental laws and regulations. The proposed CCT will allow for the continued burning of coal in Petitioner's generating units, including Indiana coal and coal from the Illinois Basin. We have also approved the estimated costs of constructing and installing the NOx Compliance Plan equipment. Thus, NIPSCO's NOx Compliance Plan constitutes QPCP.

7. **CWIP Ratemaking, AFUDC and Accounting Proposals**. The Settlement Agreement provides for certain ratemaking and accounting treatments related to costs to be incurred by NIPSCO during construction and operation of the QPCP. Specifically, the Settlement Agreement requests authority from the Commission to implement an ECRM and for NIPSCO to adjust its rates periodically in order to provide a return on its NOx capital investments until such time as the applicable QPCP is found to be "used and useful" in a NIPSCO base rate case, consistent with IC §§ 8-1-2-6.6 and 6.8 and Commission's Rule 170 IAC

4-6. Pet. Ex. A-5, Ex.A. Due to the fact that there will be a time period between the incurrence of QPCP costs and the reflection of such costs in NIPSCO's rates, pursuant to IC §§ 8-1-2-6.6 and 6.8, NIPSCO also requests authority to accrue AFUDC on its QPCP expenditures until such time as such expenditures begin receiving CWIP ratemaking treatment. The Settlement Agreement further provides for the implementation of an EERM, which will permit the recovery by NIPSCO of the related depreciation and O&M expenses of the QPCP once it is in service. Pet. Exh. A-5, Ex. B.

The Company's proposed CWIP ratemaking treatment, as provided for in the proposed ECRM, is consistent with the requirements of IC §§ 8-1-2-6.6 and 6.8 and 170 IAC 4-6. Pet. Ex. A-1, p. 4. Mr. Vajda stated that the Company proposed to commence CWIP rate-making treatment for the costs of a QPCP project once it has been under construction for at least six months. He said that Petitioner will request appropriate rate adjustments under the ECRM at six month intervals. He said that the Company proposes to continue recording AFUDC until such costs are accorded CWIP ratemaking treatment or are otherwise included in NIPSCO's basic rates. Mr. Vajda said that the Company will compute the AFUDC rate in accordance with the Uniform Systems of Accounts, Electric Plant Instructions. Pet. Ex. A-1, p. 8. When a construction project is completed and the plant is placed in service, Mr. Vajda said that the accumulated AFUDC will be included in the cost of the facilities for rate base and depreciation purposes. Pet. Ex. A-1, p. 6.

Mr. Vajda explained the calculation of the Company's weighted cost of capital that will be utilized in the ratemaking treatment of QPCP project costs. Pet. Ex. A-1, p. 8. He said that the Company will use book capital structure balances at year end for long-term debt, preferred stock and common equity, as well as other components of a regulatory capital structure such as deferred taxes, accumulated investment tax credits and post-retirement benefits. Pet. Ex. A-3. Mr. Vajda testified that the cost rates for long-term debt and preferred stock will reflect the most recent calendar year. The cost rate for common equity and customer deposits will be those approved in the Company's last electric rate case, Cause No. 38045. The deferred taxes, pre-1971 investment tax credits and the reserve for post-retirement benefits will be given a cost of zero. Pet. Ex. A-1, p. 9.

Ms. Hodges sponsored Petitioner's proposed tariff sheets, including a new Rule 46 to its General Rules and Regulations, which sets out the formula for computing the ECRM factor applicable to the individual rate schedules. Pet. Ex. D-2. Ms. Hodges stated that the proposed ECRM charge per kWh will be determined periodically by multiplying the percentage of production plant allocated to each rate schedule times the amount of QPCP related semi-annual revenue requirements designated for recovery. This calculation produces the QPCP cost to be recovered from each rate schedule. The allocated revenue requirements for each rate schedule will then be divided by the forecasted kWh sales for the next six months for each rate schedule to derive the proposed ECRM billing factors ($/kWh). Pet. Ex. D-1, p. 6.

Ms. Hodges stated that, under the terms of the Settlement Agreement, the Petitioner proposes a semi-annual filing process for the ECRM billing factors, with an annual hearing to implement new ECRM factors and "true up" the past year's collections. Pet. Ex. D-1, pp. 6-7. She said that new ECRM factors will be filed with the Commission semi-annually and will reflect QPCP costs incurred since the most recent semi-annual proceeding. The ECRM will require NIPSCO to file the appropriate tariff sheets with the Commission five business days prior to the beginning of each recovery period. The proposed tariff sheets will contain the billing factors, together with supporting documentation and a revised Appendix C in the Company's tariff, to become effective, subject to refund.[4] Ms. Hodges proposed that on an annual basis, NIPSCO will make a filing requesting approval of the ongoing five-year plan for environmental NOx compliance projects, including details of projected expenditures for the upcoming 12-month period and actual revenues collected for the prior 12-month period. According to Ms. Hodges, the annual filing will consist of testimony and exhibits related to the five-year environmental NOx Compliance Plan, including (1) an update of the status of the plan, exhibits detailing costs and construction schedules, cost-to-date, in-services dates, current balance of capital expenditures, emission allowance costs, and current operating expenses by project component, (2) an update of environmental guidelines, (3) actual information from the prior 12-month billing period, including reconciliation of actual sales with estimates used, and (4) a request for removal of the subject-to-refund obligation. Pet. Ex. D-1, pp. 7-8. Ms. Hodges sponsored exhibits that detailed information that will be included in NIPSCO's semi-annual filings. Pet. Ex. D-3 and D-5 through 10.

Mr. Vajda testified that the Settlement Agreement calls for the Company to recover by way of the EERM, reasonably incurred O&M and depreciation expenses associated with the NIPSCO's ownership and operation of the QPCP facilities, in accordance with IC § 8-1-2-42(a). Pet. Ex. A-4, p. 2. Mr. Vajda explained that, as a result of the Settlement Agreement, NIPSCO no longer was requesting that the Commission allow NIPSCO to defer depreciation and O&M expenses, as a regulatory asset, with carrying charges, to be later amortized and recovered. Instead, the Settlement Agreement provides for the current recovery of these costs through use of the EERM, which would serve as a depreciation and O&M expense tracker. He also stated that as a result of the Settlement Agreement, NIPSCO will now depreciate the QPCP projects using the same depreciation rates ordered by the Commission in Cause No. 38045, rather than over 10 years, as previously requested and permitted by IC § 8-1-2-6.7. Pet. Ex. A-4, p. 3.

Ms. Hodges described the procedures involved with the proposed EERM, as set forth in Exhibit B to the Settlement Agreement. She stated that as part of the annual QPCP filing, NIPSCO will include the actual O&M and depreciation expenses recorded on the Company's books during the previous 12-month period for QPCP projects that have been placed in service. She said that NIPSCO will add a new Rule 47 to its General Rules and Regulations applicable to electric service in order to implement the EERM. Pet. Ex. D-11, p. 4. She said that the part of the EERM charge per kWh for depreciation expense will be determined by multiplying the percentage of production plant allocated to each rate schedule times the amount of QPCP related depreciation expense approved for recovery. The part of the EERM charge for O&M will be determined by multiplying the O&M expenses approved for recovery times the composite

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4 While the Settlement Agreement contemplates submission of this information without a hearing, consistent with our findings herein, the proposed tariff sheets may not go into effect until a hearing has been conducted on these issues and an Order has been issued by the Commission. The Annual Hearing should also be utilized in order to provide for a comprehensive review of the issues by the Commission.

percentage of two elements: (1) an element for the production allocation percentage, and (2) an element for the energy allocation percentages. Ms. Hodges testified that the Greneman cost of service study provided the basis for these percentages, as described in Mr. Greneman's Supplemental Testimony admitted as Petitioner's Exhibit B-4. Ms. Hodges testified further that the allocated depreciation and O&M expenses will then be divided by the forecast kWh sales for the next twelve months in order to derive the proposed EERM rate adjustments $/kWh. Pet. Ex. D-11, p. 5.

Intervenors' Evidence. The Intervenors submitted the testimony of Reed W. Cearley. Mr. Cearley was critical of the expedited and incremental nature of the proposed ECRM cost review process, which he claimed made it a rate case for only environmental equipment, improperly excluding changes in other base rate elements, such as retirements and accumulated depreciation of existing assets. Mr. Cearley testified that NIPSCO should be required to adjust any returns it received on QPCP assets to account for accumulated depreciation related to them. Int. Ex. A-1, p. 6. Mr. Cearley argued that even though the Commission may determine NIPSCO's investment in QPCP technology is prudent, this does not mean such property is used and useful in rendering service, further contending that it may be years before the ratepayers receive any benefit from clean coal technology. Int. Ex. A-1, p. 7. Mr. Cearley was also critical of the exclusion of earnings on QPCP in the calculation of NIPSCO's earnings for the purpose of whether or not they are excessive in FAC proceedings. Int. Ex. A-1, p. 5.

8. **Commission Findings Regarding AFUDC and Related Issues**. Indiana law grants the Commission authority to approve CWIP ratemaking treatment for QPCP, and to approve requests for accounting treatment such as that proposed in this case. IC 8-1-2-6.6 (and 170 IAC 4-6-4) authorize CWIP ratemaking treatment for QPCP, while IC 8-1-2-12 and 14 give the Commission authority with respect to accounting procedures utilized by Indiana public utilities. IC § 8-1-2-42(a) authorizes the Commission to approve tracking provisions, generally.

The Commission has found in prior cases that deferred accounting requests, sufficient to avoid the negative earnings erosion associated with placing large new projects in service, may be appropriately considered and approved by the Commission. *See, Indiana-American Water Co.*, Cause No. 40442 (*Ind. Util. Reg. Comm'n*, Oct. 2, 1996); *SIGECO*, Cause No. 37978 (*Ind. Util. Reg. Comm'n*, Jan. 29, 1986); *Northwest Indiana Water Co.*, Cause No. 40402 (*Ind. Util. Reg. Comm'n*, Sept. 19, 1996); *NIPSCO*, Cause No. 37819 (*Ind. Util. Reg. Comm'n*, Nov. 27, 1985).[5]

The Commission's focus in each of its earnings erosion mitigation orders has been on the magnitude of the utility's project or projects and the earnings erosion that would occur in the absence of the requested treatment, during the period of time between the projects' in-service

5. While the Commission has historically not approved post-in-service deferred accounting of O&M expenses, the present proceeding was filed under the provisions set forth in IC § 8-1-8.8-1 *et. seq.*, which was recently passed into law in the State of Indiana, and specifically allows for the recovery of O&M expenses. Accordingly, our approval of the Settlement Agreement in this Cause includes approval of deferred accounting for O&M expenses.

date(s) until their inclusion in base rates. In this case, the evidence is clear that NIPSCO is making significant investments in pollution control property. Based on the evidence presented in this matter it is apparent that it would be virtually impossible for NIPSCO to perfectly time a rate case or cases with the in-service dates of the many QPCP projects. During the interim period between those projects' in-service dates and any subsequent rate case, the financial impact of those investments could materially and adversely impact NIPSCO's earnings in the absence of the requested ratemaking and accounting relief requested in this case.

Once pollution control equipment is found to be QPCP, then the utility is allowed to add the value of the QPCP to the value of the utility's property for ratemaking purposes (*i.e.*, CWIP ratemaking treatment is applied to the QPCP). The CWIP ratemaking treatment may be granted, among other ways, in a review proceeding under IC § 8-1-8.7 (the clean coal technology statute), or in a separate rate adjustment proceeding. *See* 170 IAC 4-6-11. The return is to be equal to the utility's weighted cost of capital, based on its capital structure and debt and preferred stock cost rates as of the valuation date for the construction work in progress and the common equity cost rate used in the utility's last base rate case. *See,* 170 IAC 4-6-14. The utility's jurisdictional revenue requirement shall be allocated among customer classes in accordance with the allocation parameters in the utility's last retail base rate case.

Petitioner has presented evidence, including the required schedules, demonstrating how it intends to recover the CWIP return, consistent with our CWIP rules. We find that the ratemaking treatment should be afforded for Petitioner's QPCP via proposed Rule 46. In accordance with 170 IAC 4-6-22, we find that the projects should be deemed to be under construction and NIPSCO should continue to receive revenues through Rule 46 until such time the Commission determines that the projects are used and useful in a proceeding that involves establishment of new NIPSCO basic rates and charges. Under 170 IAC 4-6, a utility may seek a CWIP return on additional construction costs in six-month intervals. Our rules require a hearing on each such request for the inclusion of additional CWIP in the value of the utility's property on which the utility is authorized to earn a return. 170 IAC 4-6-10, 18. NIPSCO has proposed that its semi-annual filings for its ECRM be made effective, subject to refund, pending final determination as to the reasonableness of the costs to be recovered during the annual filing. We find that this proposal should be approved, as modified by our findings herein. NIPSCO may update the value of its property for CWIP ratemaking purposes no more often than every six months, by a filing under this docket as described herein.

We also find that it is reasonable and proper for NIPSCO to accrue AFUDC related to QPCP property prior to any CWIP ratemaking treatment and that NIPSCO's EERM (Rule 47) and the annual filings to implement it, are reasonable, proper and should be approved.

9. <u>Commission Review of the Settlement Agreement</u>. Settlements presented to the Commission are not ordinary contracts between private parties. *United States Gypsum, Inc. v. Indiana Gas Co.,* 735 N.E. 2d 790, 803 (Ind. 2000). When the Commission approves a settlement, that settlement "loses its status as a strictly private contract and takes on a public interest gloss." Id. (quoting, *Citizens Action Coalition v. PSI Energy, Inc.*, 664 N.E.2d 401, 406 (Ind. Ct. App. 1996)). Thus, the Commission "may not accept a settlement merely because the private parties are satisfied; rather [the Commission] must consider whether the public interest will be served by accepting the settlement." *Citizens Action Coalition*, 664 N.E.2d at 406.

Any Commission decision, ruling, or order – including the approval of a settlement – must be supported by specific findings of fact and sufficient evidence. *United States Gypsum*, 735 N.E.2d at 795 (citing *Citizens Action Coalition v. Public Service Co.*, 582 N.E.2d 330, 331 (Ind. 1991)). The Commission's procedural rules require that settlements be supported by probative evidence. 170 IAC 1-1.1-17(d). Thus for the Commission to approve the Settlement Agreement, we must conclude that the evidence in this Cause sufficiently supports the conclusions that the Settlement Agreement is reasonable, just, and consistent with the purpose of I.C. § 8-1-2, and that the agreement serves the public interest.

For the reasons previously discussed herein, we find that the Settlement Agreement is supported by probative evidence, is reasonable, just and consistent with the purpose of IC § 8-1-2, sets forth a reasonable resolution of the issues herein and should be approved.

10. Effect of Settlement Agreement. Based on our review of the Settlement Agreement and evidence in support thereof, we find that the terms negotiated by the OUCC and NIPSCO, as modified by this Order, are in the public interest and should be approved. The Settlement Agreement should not be used as precedent in any other proceeding or for any other purpose, except to the extent necessary to implement or enforce its terms. Consequently, with regard to future citation of the Settlement Agreement, we find that our approval herein should be construed in a manner consistent with our finding in *Richmond Power & Light*, Cause No. 40434, (*Ind. Util. Reg. Comm'n*, March 19, 1997).

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

1. The attached Settlement Agreement is hereby approved consistent with the terms set forth in this Order and is hereby incorporated by reference.

2. Petitioner is issued a Certificate of Public Convenience and Necessity for the construction and use of its proposed Clean Coal Technology, as described in this Order. This Order constitutes the certificate.

3. Petitioner's proposed qualified pollution control property for its NOx Compliance Plan equipment is approved for use, in accordance with 170 IAC 4-6-4.

4. Petitioner's cost estimates for its Compliance Plan equipment are reasonable and hereby approved.

5. Petitioner's proposed Rules 46 and 47 are approved and shall go into effect upon the filing of the final Rules with the Commission's Electricity Division.

6. Petitioner's request for ongoing review of its clean coal technology projects and

7. The Petitioner is hereby granted authority to modify its accounting procedures to allow Petitioner to capitalize AFUDC on its NOx Compliance Plan facilities until the commencement of CWIP rate making treatment or the date NIPSCO's investment in such facilities is included in Petitioner's rate base for retail electric rates.

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

McCARTY, HADLEY, RIPLEY AND ZIEGNER CONCUR:

APPROVED: NOV 26 2002

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

Nancy E. Manley

Nancy E. Manley, Secretary to the Commission

STATE OF INDIANA

BEFORE THE

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE CONSTRUCTION OF CLEAN COAL TECHNOLOGY UNDER IND. CODE § 8-1-8.7, et. seq., APPROVAL OF THE USE OF QUALIFIED POLLUTION CONTROL PROPERTY UNDER IND. CODE § 8-1-2-6.6 AND AUTHORIZATION TO DEFER AND AMORTIZE DEPRECIATION AND OPERATION AND MAINTENANCE EXPENSES ASSOCIATED WITH CLEAN COAL TECHNOLOGY.	)	CAUSE NO. 42150

STIPULATION AND SETTLEMENT AGREEMENT

This Stipulation and Settlement Agreement ("Settlement Agreement") is entered into, as of the 20th day of June, 2002, by and among Respondent Northern Indiana Public Service Company ("NIPSCO"), the Indiana Office of Utility Consumer Counselor (the "Public" or "OUCC"), , and any other parties signatory hereto (collectively, the "Parties"). The Parties, having been duly advised by their respective staff, experts and counsel, stipulate and agree for purposes of settling this matter that the terms and conditions hereinafter set forth below are a fair and reasonable resolution of the issues in this Cause, subject to their incorporation into a final order of the Indiana Utility Regulatory Commission ("IURC" or "Commission"), without modification or further condition unacceptable to any Party. If the Commission does not approve the terms of this Settlement Agreement in its entirety and incorporate them in a final order, this Settlement Agreement shall be null and void and deemed withdrawn, unless otherwise agreed to in writing by the Parties.

Terms and Conditions of Settlement Agreement

1. Rate Treatment of Costs. The Parties shall request the Commission's resolution of this Cause on the terms substantially as set forth herein. In resolving this matter, the Parties shall request that the IURC (1) issue a certificate of public convenience and necessity approving NIPSCO's environmental compliance plan as presented in this proceeding and (2) authorize NIPSCO to implement the environmental cost recovery mechanisms attached hereto as Exhibits A and B, which shall allow NIPSCO the opportunity to recover in its rates (a) a return at rates computed in accord with 170 IAC 4-6 on its prudently incurred investment in Clean Coal Technology ("CCT") until the Commission determines the used and usefulness of such facilities, through semi-annual filings with the Commission, in accordance with I.C. 8-1-2-6.6 and 170 IAC 4-6, and (b) after commencement of commercial operation of said facilities, through annual filings with the Commission, its reasonably incurred incremental O&M and depreciation expense associated with NIPSCO's ownership and use of the CCT, in accordance with I.C. 8-1-2-42(a). Pursuant to procedures agreed to by the Parties, NIPSCO will file annually for Commission approval of its ongoing, five-year plan for environmental compliance, including details of NIPSCO's projected capital expenditures for the upcoming 12-month period and actual expenditures for the most recent 12-month period. NIPSCO will file semi-annually for Commission approval of a billing surcharge to reflect a return on environmental capital expenditures made. These surcharges will be subject to refund until the Commission has completed its annual investigation of the costs and has approved them. Recovery of operating and depreciation expenses shall begin only after the related facilities commence operation and

the Commission has found such expenses reasonably incurred. NIPSCO will file on an annual basis its request for recovery of <u>actual</u> CCT O&M and depreciation expenses incurred the previous 12 months. Depreciation expense will be predicated upon the Company's current depreciation rates. Allocation of demand related costs shall be based on the allocation methodology in the cost study shown in Respondent's Revised Exhibit RDG – 2 and related work-papers in IURC Cause No. 41746, reproduced as Petitioner's Exhibit RDG-2 in this Cause No. 42150. The parties agree that NIPSCO's return on its investment in CCT should be excluded from NIPSCO's FAC earnings cap calculation and that exclusion is a part of this Settlement Agreement. The OUCC will not offer into evidence the testimony of Wes R. Blakely prefiled herein, as Public's Exhibit No. 1. The provisions of this paragraph shall not affect any position which a Party may wish to advocate regarding the revenues related to the sale of emission allowances.

2. <u>Settlement Agreement Confidential Until Filed</u>. This Settlement Agreement shall be privileged and confidential until filed with the IURC. However, the Parties may discuss the terms of this Settlement Agreement with other parties in this Cause in an effort to encourage them to enter into or support this settlement. The joinder or non-joinder of any other party shall not affect the settlement agreed to herein by the Parties, subject to final approval by the IURC.

3. <u>Evidence</u>. The evidence presented and to be presented in this Cause, including this Settlement Agreement, constitutes substantial, probative evidence sufficient to support this Settlement Agreement and provide an adequate evidentiary basis upon which the Commission can make any finding of fact and conclusion of law necessary for the approval of this Settlement Agreement and a final order resolving the issues herein on the terms hereof. If the IURC does not approve by order the material terms of this Settlement Agreement, this Settlement Agreement

shall be null and void and mutually withdrawn, unless the Parties agree in writing to accept such result. The Parties shall not support any challenge or appeal of this Settlement Agreement or any IURC order approving and/or adopting the terms of this Settlement Agreement, as a just and reasonable resolution of this Cause.

4. <u>Binding Agreement</u>. The undersigned represent and agree that they are fully authorized to execute this Settlement Agreement on behalf of their designated Party. This Settlement Agreement may be executed in counterparts and shall inure to the benefit of, and be binding upon, the successors, heirs and assigns of the Parties.

NORTHERN INDIANA PUBLIC SERVICE COMPANY

By: ____________________
Daniel D. Gavito

INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR

By: Anne E. Becker

Anne E. Becker

RATE 811
RATE FOR ELECTRIC SERVICE
RESIDENTIAL

TO WHOM AVAILABLE
Available for RESIDENTIAL SERVICE to RESIDENTIAL and FARM Customers located on the Company's distribution lines suitable and adequate for supplying the service requested, subject to the conditions set forth in this schedule and the accompanying Rules and Regulations of this tariff.

CHARACTER OF SERVICE
Alternating current, sixty Hertz, single phase, at a voltage of 120/240 volts three-wire, or 120/208 volts three-wire, as designated by the Company.

RATE

Customer Charge
$5.95 including the charge for 36 kilowatt hours.

Energy Charge

16.522	cents per kilowatt hour for the next	14	kilowatt hours used per month
12.041	cents per kilowatt hour for the next	150	kilowatt hours used per month
9.637	cents per kilowatt hour for all over	200	kilowatt hours used per month

ADJUSTMENT FOR CUSTOMERS WITH ELECTRIC SPACEHEATING
The above schedule of rates will be modified for any customer who regularly uses and depends for spaceheating service primarily upon permanently installed electric spaceheating facilities as follows:

7.149 cents per kilowatt hour for all use in excess of 500 kilowatt hours during any billing period more than half of which is within any calendar month from October to April, inclusive.

RATE ADJUSTMENT
The above rates are subject to a Purchased Power Cost Adjustment Tracking Factor, in accordance with the Order of the Indiana Utility Regulatory Commission approved December 17, 1976, in Cause No. 34614. The Purchased Power Cost Adjustment Tracking Factor stated in Appendix A, Sheet No. 58, is applicable hereto and is issued and effective at the dates shown on Appendix A.

ENVIRONMENTAL COST RECOVERY MECHANISM FACTOR
The above rates are subject to an Environmental Cost Recovery Mechanism Factor set forth in Rule 45 of the accompanying Rules and Regulations, in accordance with the Order of the Indiana Utility Regulatory Commission approved (DATE), in Cause No. 42150. The Environmental Cost Recovery Mechanism Factor stated in Appendix C, Sheet No. 59A, is applicable hereto and is issued and effective at the dates shown on Appendix C.

ENVIRONMENTAL EXPENSE RECOVERY MECHANISM FACTOR
The above rates are subject to an Environmental Expense Recovery Mechanism Factor set forth in Rule 47 of the accompanying Rules and Regulations, in accordance with the Order of the Indiana Utility Regulatory Commission approved (DATE), in Cause No. 42150. The Environmental Expense Recovery Mechanism Factor stated in Appendix E, Sheet No. 59C, is applicable hereto and is issued and effective at the dates shown on Appendix E.

APPENDIX C

RATE ADJUSTMENT

The Rate Adjustment in Rates 811, 812, 813, 820, 821, 822, 823, 824, 825, 826, 832, 833, 836, 841, 844, 845, and 847 shall be on the basis of a charge to reflect the rate base treatment of qualified pollution control costs, set forth in Rule 45 of the accompanying General Rules and Regulations and in accordance with the Order of the Indiana Utility Regulatory Commission approved ____________ in Cause No. 42150, as follows:

RATE SCHEDULES

Rate 811	A CHARGE of $0.______ per kwh used per month
Rate 812	A CHARGE of $0.______ per kwh used per month
Rate 813	A CHARGE of $0.______ per kwh used per month
Rate 820	A CHARGE of $0.______ per kwh used per month
Rate 821	A CHARGE of $0.______ per kwh used per month
Rate 822	A CHARGE of $0.______ per kwh used per month
Rate 823	A CHARGE of $0.______ per kwh used per month
Rate 824	A CHARGE of $0.______ per kwh used per month
Rate 825	A CHARGE of $0.______ per kwh used per month
Rate 826	A CHARGE of $0.______ per kwh used per month
Rate 832	A CHARGE of $0.______ per kwh used per month
Rate 833	A CHARGE of $0.______ per kwh used per month
Rate 836	A CHARGE of $0.______ per kwh used per month
Rate 841	A CHARGE of $0.______ per kwh used per month
Rate 844	A CHARGE of $0.______ per kwh used per month
Rate 845	A CHARGE of $0.______ per kwh used per month
Rate 847	A CHARGE of $0.______ per kwh used per month

Issued Date ____________

Issued By
Daniel D. Gavito
Vice President, Indiana, Regulatory and Government Policy
Merrillville, Indiana

Effective Date ____________

GENERAL RULES AND REGULATIONS
APPLICABLE TO ELECTRIC SERVICE

43. UNMETERED SERVICE - CABLE TELEVISION - (Obsolete) (continued)
The available General Service rate schedule shall be applicable to service furnished hereunder.

This Rule shall be applicable only until such time as the Company is capable of installing meters at all existing unmetered installations. All new installations shall be metered.

44. UTILITY RESIDENTIAL WEATHERIZATION PROGRAM (URWP)
The Company has replaced its Utility Residential Weatherization Loan Program (URWP) with a program for NIPSCO Energy Saver Loans as follows:

A NIPSCO Energy Saver Loan will be available through branch offices of NBD Bank and its affiliates located throughout the Company's service territory. The loans will be available for energy improvements to any residential customer upon approval for credit by NBD. The loans will be available at NBD's current interest rates, with principal amounts ranging from a minimum of $1,000 to a maximum of $10,000.

Customers must contact a participating NBD Bank or affiliated branch during regular business hours to apply for or inquire about the specific terms and conditions of a NIPSCO Energy Saver Loan. NBD is an Equal Housing and Equal Opportunity Lender.

45. ADJUSTMENT OF CHARGES FOR ENVIRONMENTAL COST RECOVERY MECHANISM
Energy charges in the Rate Schedules included in this tariff are subject to charges approved by the Indiana Utility Regulatory Commission to reflect rate base treatment for qualified pollution control property, and such charges shall be increased or decreased to the nearest 0.001 mill ($.000001) per KWH in accordance with the following:

Environmental Cost Recovery Mechanism ("ECRM") = (RxP)/S

Where:

(a) "ECRM" is the rate adjustment for each Rate Schedule representing the ratemaking treatment for qualified pollution control property.
(b) "R" equals the total revenue requirement based upon the costs for the qualified pollution control property.
(c) "P" represents the Production Demand Allocation percentage for the Rate Schedule.
(d) "S" is the forecast 6-month KWH sales for the Rate Schedule.

The ECRM as computed above shall be further modified to allow the recovery of gross receipts taxes and other similar revenue based tax charges occasioned by the ECRM revenues and later reconciled with actual sales and revenues.

See Appendix C, Sheet No. 59A, for ECRM's per KWH charge for each Rate Schedule.

Issued Date

Issued By
Daniel D. Gavito
Vice President, Indiana, Regulatory and Government Policy
Merrillville, Indiana

Effective Date

RATE 811
RATE FOR ELECTRIC SERVICE
RESIDENTIAL

TO WHOM AVAILABLE

Available for RESIDENTIAL SERVICE to RESIDENTIAL and FARM Customers located on the Company's distribution lines suitable and adequate for supplying the service requested, subject to the conditions set forth in this schedule and the accompanying Rules and Regulations of this tariff.

CHARACTER OF SERVICE

Alternating current, sixty Hertz, single phase, at a voltage of 120/240 volts three-wire, or 120/208 volts three-wire, as designated by the Company.

RATE

Customer Charge
$5.95 including the charge for 36 kilowatt hours.

Energy Charge

16.522 cents per kilowatt hour for the next	14	kilowatt hours used per month
12.041 cents per kilowatt hour for the next	150	kilowatt hours used per month
9.637 cents per kilowatt hour for all over	200	kilowatt hours used per month

ADJUSTMENT FOR CUSTOMERS WITH ELECTRIC SPACEHEATING

The above schedule of rates will be modified for any customer who regularly uses and depends for spaceheating service primarily upon permanently installed electric spaceheating facilities as follows:

7.149 cents per kilowatt hour for all use in excess of 500 kilowatt hours during any billing period more than half of which is within any calendar month from October to April, inclusive.

RATE ADJUSTMENT

The above rates are subject to a Purchased Power Cost Adjustment Tracking Factor, in accordance with the Order of the Indiana Utility Regulatory Commission approved December 17, 1976, in Cause No. 34614. The Purchased Power Cost Adjustment Tracking Factor stated in Appendix A, Sheet No. 58, is applicable hereto and is issued and effective at the dates shown on Appendix A.

ENVIRONMENTAL COST RECOVERY MECHANISM FACTOR

The above rates are subject to an Environmental Cost Recovery Mechanism Factor set forth in Rule 45 of the accompanying Rules and Regulations, in accordance with the Order of the Indiana Utility Regulatory Commission approved (DATE), in Cause No. 42150. The Environmental Cost Recovery Mechanism Factor stated in Appendix C, Sheet No. 59A, is applicable hereto and is issued and effective at the dates shown on Appendix C.

ENVIRONMENTAL EXPENSE RECOVERY MECHANISM FACTOR

The above rates are subject to an Environmental Expense Recovery Mechanism Factor set forth in Rule 47 of the accompanying Rules and Regulations, in accordance with the Order of the Indiana Utility Regulatory Commission approved (DATE), in Cause No. 42150. The Environmental Expense Recovery Mechanism Factor stated in Appendix E, Sheet No. 59C, is applicable hereto and is issued and effective at the dates shown on Appendix E.

APPENDIX E

RATE ADJUSTMENT

The Rate Adjustment in Rates 811, 812, 813, 820, 821, 822, 823, 824, 825, 826, 832, 833, 836, 841, 844, 845, and 847 shall be on the basis of a charge to reflect the recovery of Operation and Maintenance and Depreciation Expenses related to Qualified Pollution Control Property placed in service, set forth in Rule 47 of the accompanying General Rules and Regulations and in accordance with the Order of the Indiana Utility Regulatory Commission approved ____________ in Cause No. 42150, as follows:

RATE SCHEDULES

Rate 811	A CHARGE of $0.______ per kwh used per month
Rate 812	A CHARGE of $0.______ per kwh used per month
Rate 813	A CHARGE of $0.______ per kwh used per month
Rate 820	A CHARGE of $0.______ per kwh used per month
Rate 821	A CHARGE of $0.______ per kwh used per month
Rate 822	A CHARGE of $0.______ per kwh used per month
Rate 823	A CHARGE of $0.______ per kwh used per month
Rate 824	A CHARGE of $0.______ per kwh used per month
Rate 825	A CHARGE of $0.______ per kwh used per month
Rate 826	A CHARGE of $0.______ per kwh used per month
Rate 832	A CHARGE of $0.______ per kwh used per month
Rate 833	A CHARGE of $0.______ per kwh used per month
Rate 836	A CHARGE of $0.______ per kwh used per month
Rate 841	A CHARGE of $0.______ per kwh used per month
Rate 844	A CHARGE of $0.______ per kwh used per month
Rate 845	A CHARGE of $0.______ per kwh used per month
Rate 847	A CHARGE of $0.______ per kwh used per month

GENERAL RULES AND REGULATIONS
APPLICABLE TO ELECTRIC SERVICE

47. ADJUSTMENT OF CHARGES FOR ENVIRONMENTAL EXPENSE RECOVERY MECHANISM

Energy charges in the Rate Schedules included in this tariff are subject to charges to reflect the recovery of operation and maintenance and depreciation expenses for qualified pollution control property placed in service, and such charges shall be increased or decreased to the nearest 0.001 mill ($.000001) per KWH in accordance with the following:

Environmental Expense Recovery Mechanism ("EERM") = ((D x P) + (O&M x Pc)) / S

Where:

(a) "EERM" is the rate adjustment for each Rate Schedule representing the recovery of operation and maintenance and depreciation expenses for qualified pollution control property placed in service.
(b) "D" equals the total annual depreciation expense for the qualified pollution control property placed in service.
(c) "P" represents the Production Demand Allocation Percentage for each Rate Schedule.
(d) "O&M" equals the total annual operation and maintenance expense for the qualified pollution control property placed in service.
(e) "Pc" a percentage value, equals a composite allocation based on:
   (1) x(%) times P defined in (c) above for each Rate Schedule; and
   (2) (1-x)(%) times "Te", where:
      "Te" represents the Energy Allocation Percentage for each Rate Schedule; and
(f) "S" is the forecast 12-month KWH sales for each Rate Schedule.

The EERM as computed above shall be further modified to allow the recovery of gross receipts taxes and other similar revenue based tax charges occasioned by the EERM revenues and later reconciled with actual sales and revenues.

See Appendix E, Sheet No. 59C, for EERM's per KWH charge for each Rate Schedule.

WHERE AVAILABLE

ALL TERRITORY FURNISHED ELECTRIC SERVICE

CERTIFICATE OF SERVICE

The undersigned certifies that he has served copies of the foregoing joint petition, on the following parties, by hand delivery or United States mail, first class postage prepaid, this 20th day of June, 2002.

Rick D. Doyle
Robert W. Wright
Doyle, Wright & Dean-Webster, LLP
399 North Madison Avenue
Greenwood, IN 46142

Donald P. Levinson
Levinson & Levinson
122 W. 79th Avenue
Merrillville, IN 46410

Shaw R. Friedman
Friedman & Associates, p.c.
705 Lincolnway
LaPorte, IN 46350

Peter L. Hatton

Peter L. Hatton, Attorney for
Northern Indiana Public Service Company

INIMAN2 644941v1

ORIGINAL

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY FOR APPROVAL OF: (1) AN ADJUSTMENT TO ITS ELECTRIC SERVICE RATES THROUGH ITS ENVIRONMENTAL COST RECOVERY MECHANISM FACTOR PURSUANT TO IND. CODE 8-1-2-6.6, 8-2-1-6.8, CH. 8-1-8.4, CH. 8-1-8.7, CH. 8-1-8.8 AND 170 IAC 4-6-1, ET SEQ. AND THE COMMISSION'S ORDERS IN CAUSE NOS. 42150, 43188, 43969, 44012 AND 44311; AND (2) MODIFICATIONS OF AND REVISED COST ESTIMATES RESPECTING ENVIRONMENTAL COMPLIANCE PROJECTS SET FORTH IN ITS FOURTEENTH PROGRESS REPORT PURSUANT TO THE ONGOING REVIEW PROCESS UNDER IND. CODE 8-1-8.7-7 AND APPROVED IN CAUSE NOS. 42150, 43188, 44012 AND 44311	)	CAUSE NO. 42150 ECR 24 APPROVED: OCT 29 2014

ORDER OF THE COMMISSION

Presiding Officers:
David E. Ziegner, Commissioner
Jeffery A. Earl, Administrative Law Judge

On August 1, 2014, Northern Indiana Public Service Company ("NIPSCO") filed its Verified Petition in this Cause. NIPSCO also prefiled the direct testimony and exhibits of the following:

- Ronald G. Plantz, Controller of NIPSCO;
- Kurt W. Sangster, Vice President, Major Projects; and
- Derric J. Isensee, Manager, Regulatory Support and Analysis.

On August 5, 2014, the NIPSCO Industrial Group ("Industrial Group") filed its Petition to Intervene, which was granted by the Presiding Officers in a Docket Entry dated August 18, 2014.

On October 3, 2014, the Indiana Office of Utility Consumer Counselor ("OUCC") prefiled direct testimony of Wes R. Blakley, Senior Analyst in the OUCC's Electric Division. The Industrial Group did not file evidence in this Cause.

The Commission held an evidentiary hearing was held in this Cause at 10:00 a.m. on October 10, 2014, in Hearing Room 224, 101 West Washington Street, Indianapolis, Indiana. NIPSCO, the OUCC, and the Industrial Group appeared at and participated in the hearing. No member of the public appeared or participated at the hearing.

Having considered the evidence presented and the applicable law, the Commission finds:

1. **Notice and Jurisdiction.** Notice of the hearing in this case was given and published by the Commission 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 §§ 8-1-2-6.6 and 8-1-2-6.8 and Ind. Code chs. 8-1-8.7 and 8-1-8.8, the Commission has jurisdiction over a public utility's cost recovery related to the use of clean coal technology. Therefore, the Commission has jurisdiction over NIPSCO and subject matter of this case.

2. **NIPSCO's Characteristics.** NIPSCO is a public utility organized and existing under Indiana law, with its principal office at 801 E. 86th Street, Merrillville, Indiana 46410. NIPSCO owns and operates property and equipment used for the production, transmission, delivery, and furnishing of electric utility service to the public in northern Indiana.

3. **Relief Requested.** NIPSCO seeks the following:

- Approval of an adjustment to its electric service rates through its environmental cost recovery mechanism ("ECRM") factors to reflect costs incurred in connection with its Qualified Pollution Control Property ("QPCP"), Clean Coal Technology ("CCT"), clean energy projects, and federally mandated operating and maintenance ("O&M") projects (collectively "Environmental Compliance Projects"); and
- Approval of its fourteenth progress report.

4. **Commission Discussion and Findings Regarding ECRM.**

A. **Billing Period.** Mr. Isensee testified that consistent with Rider 672 – Adjustment of Charges for Environmental Cost Recovery Mechanism, NIPSCO requests approval of its ECRM factors to be applicable to the bills rendered during the billing cycles of November 2014 through April 2015. The ECRM factors include actual costs through June 30, 2014, as well as a reconciliation of projected period recoveries of ECRM revenue with actual revenue during the period November 1, 2013 through April 30, 2014.

B. **Environmental Compliance Project Investment.** Mr. Isensee testified the total cost of Environmental Compliance Projects under construction, net of accumulated depreciation, upon which NIPSCO is authorized to earn a return is $658,375,270. He stated the construction costs include an allowance for funds used during construction ("AFUDC"). Mr. Plantz testified he computed the AFUDC in accordance with the FERC Uniform System of Accounts. Mr. Isensee testified that if the Commission approves the proposed ratemaking treatment for the values shown on Schedules 1, 1A, and 1B of Exhibit 1 attached to NIPSCO's Verified Petition initiating this Cause, NIPSCO will cease accruing AFUDC on those costs once such amounts are being recovered through rates.

Mr. Sangster testified that Schedules 1, 1A, and 1B of Exhibit 1 attached to NIPSCO's Verified Petition initiating this Cause describe NIPSCO's Environmental Compliance Projects under construction that have been approved by the Commission and on which NIPSCO proposes to earn a return. Schedules 1, 1A, and 1B set out a brief description of the project, approved cost estimates, the construction start dates, the anticipated in-service dates, and the current and prior investment values for each project. The costs for NIPSCO's Environmental Compliance Projects have been compiled through June 30, 2014. Mr. Sangster also testified that all of the projects for which NIPSCO is seeking ratemaking treatment in this Cause have been under construction for at least six months.

Based on the evidence presented, we find that NIPSCO's request to begin earning a return on \$658,375,270, the value of its Environmental Compliance Projects, net of accumulated depreciation, is reasonable and we approve the request.

C. <u>Semi-Annual Revenue Requirement.</u> NIPSCO requests approval of a Semi-Annual Revenue Requirement of \$32,525,363 and an Adjusted Semi-Annual Revenue Requirement of \$30,132,226 after adjusting for the prior period reconciliation.

Mr. Plantz computed NIPSCO's proposed semi-annual return on its Environmental Compliance Projects at June 30, 2014, of a net amount of \$32,525,363, which is the product of the value of NIPSCO's Environmental Compliance Projects multiplied by the debt and equity components of its weighted cost of capital, adjusted for taxes and multiplied by 0.50. Petitioner's Exhibit 1, Schedule 7 shows that NIPSCO's Adjusted Semi-Annual Revenue Requirement is \$30,132,226 after including the prior period reconciliation.

Mr. Plantz sponsored the calculation of NIPSCO's 6.58% weighted cost of capital, using its full regulatory capital structure, per books, at June 30, 2014, which is the date of valuation of the Environmental Compliance Projects in accordance with 170 I.A.C. 4-6-14. He testified the cost rates for long-term debt reflect the 12 months ended June 30, 2014. He also testified the cost rates for common equity capital of 10.2% and customer deposits of 4.43% are those approved by the 2011 Rate Order. He stated deferred taxes and the reserve for post-retirement benefits are treated as zero-cost capital and the cost of post-1970 investment tax credits reflects the weighted costs of long-term debt and common equity capital.

Mr. Plantz stated NIPSCO's weighted average cost of capital of 6.58% reflects a 7-basis-point increase from the 6.51% approved in the ECR 23 Order.

Based on the evidence presented, we find that NIPSCO's proposed Adjusted Semi-Annual Revenue Requirement of \$30,132,226 is reasonable, and we approve the revenue requirement.

D. <u>Allocation of Semi-Annual Environmental Compliance Project Revenue Requirement.</u> Mr. Isensee sponsored Schedule 5 of Exhibit 1 which shows the production allocation percentages attributable to each of NIPSCO's rate schedules. These allocation percentages, which were approved by the ECR 19 Order, are adjusted to reflect the significant migration of customers among Rates 621, 624, 625, 626, and 632. Mr. Isensee testified this adjustment is appropriate in order to prevent any unintended consequences of the migration of customers between rates and to properly allocate their share of capital charges, and is consistent with the adjustments most recently approved by the Commission in its ECR 23 Order.

Based on the evidence presented, we find that NIPSCO's ECRM factors have been allocated on the basis of the 12 Coincident Peak ("CP") method in accordance with our ECR 19 Order.

E. <u>Reconciliation of Prior Period Recoveries.</u> Mr. Isensee testified that Schedule 6 of Exhibit 1 shows NIPSCO's reconciliation of projected period recoveries of ECRM revenue with actual revenue during the period from November 1, 2013 to April 30, 2014.

NIPSCO's total computed under- or over-recoveries of ECRM revenue for this period are reflected in Column 5. Based on the evidence presented, we find that NIPSCO properly included the reconciliation in its ECRM calculations.

F. New ECRM Factors. Mr. Isensee sponsored Exhibit 2 (Appendix D - Environmental Cost Recovery Mechanism Factor) showing the ECRM factors applicable to the various NIPSCO rate schedules and explained how the ECRM factors were developed. Mr. Isensee testified that the estimated average monthly bill impact for a typical residential customer using 688 kWh per month is $3.70, which is a $0.76 increase from what a customer would pay today using the current ECRM Factors. Mr. Blakley testified that nothing came to his attention that would indicate that NIPSCO's calculation of estimated ECRM adjustment factors for the relevant period is unreasonable.

Based on the evidence presented, we approve the proposed ECRM factors set forth in Petitioner's Exhibit 2 to be applicable for bills rendered during the billing cycles of November 2014 through April 2015.

G. Residential Space Heating Transition Plan. In Cause No. 44436, NIPSCO requested approval of a revenue neutral proposal to transition residential space heating customers from Rates 611, 612, and 613 to Rate 611 in accordance with the Commission's December 21, 2011 Order in Cause No. 43969 that approved a Stipulation and Settlement Agreement. In Cause No. 44436, NIPSCO proposed that the transition plan would take place over a 5-year period, and would evenly increase the customers' bills each year until all customers are paying the Rate 611 Energy Charges at the end of the 5-year period. However, NIPSCO proposed that in the first year of the transition, the trackers applicable to Rates 612 and 613 would be combined with the trackers for Rate 611, effectively creating one set of tracker factors for the three rates. NIPSCO proposed to begin the transition with the first billing cycle for the billing month of January 2015. Mr. Isensee testified that if NIPSCO's proposed mechanism for the phase-out of residential space heating discounts is approved by the Commission in Cause No. 44436, NIPSCO will submit revised tariffs to the Commission's Electricity Division to adjust the rates and charges for Rates 611, 612, and 613 prior to January 1, 2015. He explained that this filing would include a revision to the ECRM factors to combine the factors applicable to Rates 611, 612, and 613 into one factor applicable to each of those rates. He stated that on January 1, 2015, the ECRM factors for Rates 611, 612, and 613 would all be equal. The revised 611, 612, and 613 factors that would be applicable in the first billing cycle of January 2015 pending the outcome of Cause No. 44436 were set forth on Petitioner's Exhibit No. DJI-1. On September 3, 2014, the Commission issued a final order in Cause No. 44436, in which we approved NIPSCO's proposed space heating transition plan. Therefore, we find that NIPSCO should, prior to January 1, 2015, submit a revised tariff to the Commission's Electricity Division with a revision to the ECRM factors to combine the factors applicable to Rates 611, 612, and 613 into one factor applicable to each of those rates to be effective for the January 2015 billing cycle.

5. Commission Findings and Conclusions Regarding Progress Report. In the 42150 Order, the Commission approved NIPSCO's proposal that the Commission maintain an ongoing review of its QPCP construction and expenditures and submit to the Commission annually a report of any revisions of its plan and cost estimates for such construction ("Progress Report"). In its 43526 Order, the Commission ordered NIPSCO to file its Progress Reports on the status of QPCP tracked in the ECRM as part of its ECRM filings rather than in a separate proceeding. The

Phase I 44012 Order approved NIPSCO's request to file semi-annual progress reports (as opposed to annual progress reports) as part of the ongoing review process under Ind. Code § 8-1-8.7-7.

Pursuant to the ongoing review process under Ind. Code § 8-1-8.7-7 and as approved in Cause No. 44311, NIPSCO requests approval of its Fourteenth Progress Report on the status of Environmental Compliance Projects tracked in the ECRM and EERM and approval to recover the revised costs of its Environmental Compliance Projects through the ECRM and EERM.

Since its Thirteenth Progress Report approved by the Commission in Cause No. 42150 ECR 23, NIPSCO has identified aspects of its Compliance Plan that require further modification. Mr. Sangster testified that Exhibit PR attached to NIPSCO's Verified Petition initiating this Cause sets forth NIPSCO's Compliance Plan containing the NOx Compliance Plan, CAIR/CAMR Compliance Plan, Multi-Pollutant Compliance Plan, and MATS Compliance Plan highlighted to show necessary changes and NIPSCO's updates of estimated costs. The plan modifications can be broken down into several categories: scheduling changes, additions and/or subtractions from the Compliance Plan, and changes in estimated costs.

Mr. Sangster testified that the Unit 14 FGD Facility Addition and Unit 14/15 FGD Common facilities were successfully put into service on November 19, 2013, and Unit 14 is currently meeting SO2 emissions requirements. Tuning and performance guarantee testing has completed. The Unit 15 FGD Facility Addition continues to progress and remains on-schedule and on-budget, and it is scheduled to make final tie-ins during the 2014 Unit 15 outage and be put into service in November 2014. The total cost estimate for the three Schahfer FGD projects has not changed ($500 million total for Unit 14 FGD, Unit 15 FGD and Unit 14/15 Common Facilities). Similar to ECR 23, the allocation between the three work orders has shifted slightly. The total costs have not changed, but NIPSCO anticipates it will reallocate costs slightly between the separate work orders periodically until program completion.

With respect to the Michigan City Unit 12 FGD Facility Addition, Mr. Sangster testified that the project is progressing on-schedule. Construction began March 25, 2013. NIPSCO has awarded the major equipment supply contracts, the engineering contract, and the installation contracts. The equipment supply and electrical installation labor contracts have increased from the original +/- 40% estimate in Cause No. 44012. These two elements of the project are forecasted to cause the total project cost to be in excess of the original estimate. NIPSCO is evaluating options to reduce the impact of the cost increases from the equipment supply and the electrical installation labor contract and will subsequently use this information to determine the total cost impact to the project. At this time, NIPSCO is forecasting that the Unit 12 projects approved in Cause No. 44012 Phase III will not exceed the 25% cap set forth in Cause No. 44012 Phase III.

With respect to the Unit 14 TR Set Project, Mr. Sangster testified that construction was completed and TR sets went into service on November 19, 2013. He testified the Unit 18 TR Set Project completed construction and went into service on May 5, 2014. The remainder of the TR Set projects, Unit 15 and Unit 17 TR Sets, are progressing on-schedule and on-budget. Mr. Sangster stated the modifications to the construction start for Unit 15 and the in-service date for Unit 18, as shown on Exhibit PR, were changed to reflect actual dates.

With respect to the Units 7, 8, 12, 14, and 15 ACI projects, Mr. Sangster testified that the projects are progressing on-schedule and on-budget. The Architectural/Engineer (AE), Original

Equipment Manufacturer (OEM), the Foundations, and the General Work contracts have been awarded. He testified the Pre-Fabricated Building contract is in the process of being awarded.

With respect to the Fuel Additive projects at Units 7, 8, 12, 14, and 15 approved in Cause No. 44311, Mr. Sangster testified that NIPSCO is currently conducting performance testing to determine the effect different Activated Carbons and Fuel Additives have on the Mercury removal from the flue gas stream. Once those tests are complete NIPSCO will be able to develop specifications for the Fuel Additive Systems. He stated the Fuel Additive projects for Units 7, 8, 12, 14, and 15 are progressing on-schedule with a planned construction start date of April 2015.

With respect to scheduling changes for any of the projects in the compliance plan, Mr. Sangster testified that the construction start date for the Unit 15 TR Sets, the Unit 7 ACI, and the Unit 8 ACI projects were revised to show the actual start of construction. The in-service date for the Unit 18 TR Sets Project was revised to show the actual in-service date. The Unit 12 ACI, the Unit 14 ACI System, and the Unit 15 ACI System projects construction start dates were revised to reflect the current schedules.

With respect to additions and/or subtractions from the Compliance Plan, Mr. Sangster testified that NIPSCO has included three catalyst layer projects to its Compliance Plan in the Fourteenth Progress Report. These projects include: (1) Unit 7 3rd Catalyst Layer (replacement); (2) Unit 12 1st Catalyst Layer (replacement); and (3) Unit 14 1st Catalyst Layer (replacement). All three of the requested catalyst layer projects are replacement layers, and NIPSCO requests ratemaking treatment consistent with the Commission's Order in Cause No. 42150 ECR 21. He stated that NIPSCO is also requesting approval of a Unit 15 ESP Flow Modification MATS O&M Project.

Mr. Sangster testified that the Unit 15 ESP Flow Modification MATS O&M Project is a federally mandated O&M Project approved as part of the MATS Compliance Plan in Cause No. 44311. NIPSCO began the Unit 15 ESP Flow Modeling Study in November of 2013 and issued the final report in May of 2014. He stated the original project budget was $300,000. Due to some recent flow model work on Unit 15 for the Unit 15 FGD Addition, the scope for this flow model study was reduced with final costs projected to be around $100,000, once all invoices are paid.

Mr. Sangster testified that the Unit 15 ESP flow modeling tests came back with some recommendations to improve the flow, which include modification of the East and West box inlet perforated plates and modification of the perforated plates on each East and West box outlet. He stated NIPSCO is working to complete these modifications during the Unit 15 Fall 2014 outage, but due to the tight schedule and the congestion due to the Unit 15 TR Sets Project, this project may have to be delayed until the spring 2016 outage. Mr. Sangster testified that estimated cost to complete the modifications is $650,000, and due to the fact that the project consists of modifications, this work will be an O&M project. These costs include engineering, procurement, fabrication, scaffolding, and installation.

Mr. Sangster testified that the Unit 15 ESP Flow Modification MATS O&M Project is a federally mandated compliance project because the MATS rule is a requirement imposed on NIPSCO by the federal government—the EPA. As a result, the MATS rule is a federally mandated requirement under Ind. Code § 8-1-8.4-5(7). The Unit 15 ESP Flow Modification O&M Project is related to the direct compliance by NIPSCO with the EPA's MATS rule. The Unit 15 ESP Flow

Modification MATS O&M Project is a compliance project under Ind. Code § 8-1-8.4-2 and the costs NIPSCO will incur in connection with the Unit 15 ESP Flow Modification Project are federally mandated costs under Ind. Code § 8-1-8.4-4.

Mr. Sangster testified that NIPSCO has three SCR Catalyst layers that will require replacement in 2016. These layers are: (1) Unit 7 3rd Catalyst Layer (replacement); (2) Unit 12 1st Catalyst Layer (replacement); and (3) Unit 14 1st Catalyst Layer (replacement). The estimated cost to complete the Unit 7 3rd Catalyst Layer (replacement) is $1,200,000; (2) Unit 12 1st Catalyst Layer (replacement) is $2,635,000; and (3) Unit 14 1st Catalyst Layer (replacement) is $2,700,000.

Mr. Sangster testified that NIPSCO is requesting approval of these three replacement layers, and NIPSCO requests ratemaking treatment consistent with the Commission's Order in Cause No. 42150 ECR 21. Mr. Sangster testified that without new catalyst layers being installed to remove the NOx from the flue gases, the SCR cannot function. The three additional catalyst layers will be used on three of NIPSCO's coal burning energy generating facilities, including Bailly Unit 8, Schahfer Unit 14, and Bailly Unit 7.

Mr. Sangster testified that the Revised Plan Cost Estimate Budget column on Exhibit PR was updated to reflect changes to the shift in allocation of estimated costs between the three Schahfer FGD projects (Unit 14 FGD, Unit 15 FGD, and Common Facilities for Unit 14 & 15), but the total cost estimate for the three Schahfer FGD projects has not changed ($500 million total). Specifically, NIPSCO is now projecting: (1) the Unit 14 FGD will cost $158,093,658, an increase from the cost estimate approved in the Tenth Progress Report; (2) the Unit 15 FGD will cost $148,526,353, a decrease from the cost estimate approved in the Tenth Progress Report; and (3) the Common Facilities for Unit 14 & 15 will cost $193,379,989, a decrease from the cost estimate approved in the Tenth Progress Report.

Mr. Sangster testified that the total cost estimate approved in the Thirteenth Progress Report was $860,601,408 for the Compliance Plan Capital projects and $1,575,000 for the MATS O&M Projects. The proposed revised total cost estimate for all Compliance Plan Capital Projects is $867,136,408. This represents an increase of $6,535,000 from the currently approved amount, which is due to the addition of the three Catalyst Layer Projects. The proposed revised total cost estimate for the MATS O&M Projects is $2,225,000. This represents an increase of $650,000 as a result of the Unit 15 ESP Flow Modification MATS O&M Project.

As part of its Fourteenth Progress Report, NIPSCO is requesting approval of its updated cost estimate of $867,136,408 for Compliance Plan Capital Projects and $2,225,000 for MATS O&M Projects as well as approval to recover these costs through the ECRM and EERM. This request includes a request for minor schedule modifications as well as a reallocation of costs between the three Schahfer FGD projects. This request also includes a request for approval of three replacement Catalyst Layer Projects with ratemaking treatment consistent with that granted in Cause No. 42150 ECR-21 and approval of a one-time federally mandated Unit 15 ESP Flow Modification MATS O&M Project.

The evidence presented demonstrates that the three Schahfer FGD projects are on-schedule and on-budget and the total cost estimate for the three Schahfer FGD projects has not changed ($500 million total for Unit 14 FGD, Unit 15 FGD, and Common Facilities for Unit 14 & 15). Consistent with our conclusion in Cause No. 42150 ECR 23, we find that NIPSCO's request to change the allocation of estimated costs between the three Schahfer FGD projects (Unit 14 FGD, Unit 15 FGD, and Common Facilities for Unit 14 & 15) as set forth herein is reasonable and should be approved.

In our October 16, 2013 Order in Cause No. 42150 ECR 21, we addressed the appropriate regulatory treatment for replacement catalyst layers for NIPSCO's SCR units. We held that a replacement catalyst layer for Bailly Unit 7 SCR should be included in NIPSCO's CPCN and NIPSCO should be allowed to recover the costs for the necessary replacement of catalyst layers through its ECRM. We held that NIPSCO shall be allowed to seek recovery of its full depreciation expense (return of investment) for the replacement layer, but that NIPSCO shall only be allowed to seek recovery of the incremental amount of the return on its investment for the replacement catalyst layer that exceeds the return on investment currently included in its base rates and charges for the original catalyst layer if that original catalyst layer is replaced and retired.

Consistent with our ECR 21 Order, we find that the three proposed catalyst layer projects should be included in NIPSCO's CPCN and NIPSCO should be allowed to recover the costs for the necessary replacement of catalyst layers through its ECRM and EERM. The record evidence shows that the layers meet the definition of QPCP and CCT under Indiana Code §§ 8-1-2-6.6, 8-1-2-6.8, 8-1-8.7-1, and 170 IAC 4-6-1 because they are components of air pollution control devices that directly reduce emissions of NO_x—a nitrogen based pollutant which is associated with combustion and catalyst layers associated with SCRs were not in general commercial use at the same or greater scale in new or existing facilities in the United States as of January 1, 1989. Consistent with our ECR 21 Order, we find that NIPSCO shall be allowed to seek recovery of its full depreciation expense (return of investment) for the three additional replacement catalyst layers, but that NIPSCO shall only be allowed to seek recovery of the incremental amount of the return on its investment for the replacement catalyst layers that exceeds the return on investment currently included in its base rates and charges for the original catalyst layers.

We also find the one-time federally mandated Unit 15 ESP Flow Modification MATS O&M Project should be approved. Based on the evidence presented, we conclude that the goal of Unit 15 ESP Flow Modification MATS O&M Project was to identify problems with ESP flow and solutions to those problems. The evidence shows that the Unit 15 ESP Flow Modification MATS O&M Project will implement the solution identified by the flow modeling project. The evidence also shows the Unit 15 ESP Flow Modification MATS O&M Project is a federally mandated compliance project because the MATS rule is a requirement imposed on NIPSCO by the federal government and the project is related to the direct compliance by NIPSCO with the EPA's MATS rule. Consistent with Ind. Code § 8-1-8.4-7, we find that the same "80/20" ratemaking treatment that applies to the other federally mandated MATS O&M Projects should apply to the Unit 15 ESP Flow Modification MATS O&M Project.

Based on the evidence presented and the foregoing discussion, we find the Fourteenth Progress Report is reasonable. Therefore, we approve the modifications to schedule and cost estimates contained therein, and we authorize NIPSCO to recover these costs through its ECRM and EERM.

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

1. NIPSCO is authorized to reflect the additional values of Environmental Compliance Projects identified herein in its rates and charges for electric service in accordance with NIPSCO's ECRM beginning with the November 2014 billing cycle.

2. NIPSCO shall file with the Electricity Division of the Commission, prior to placing in effect the ECRM factors 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.

3. NIPSCO shall file with the Electricity Division of the Commission, prior to January 1, 2015, an amendment to its rate schedule to effectuate the space heating transition discussed in Paragraph 4(G).

4. Pursuant to Ind. Code § 8-1-8.7-7 and as approved in Cause No. 44311, NIPSCO's modified Compliance Plan, as set forth in the Fourteenth Progress Report, is approved.

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

ORIGINAL

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY FOR APPROVAL OF: (1) AN ADJUSTMENT TO ITS ELECTRIC SERVICE RATES THROUGH ITS ENVIRONMENTAL COST RECOVERY MECHANISM FACTOR PURSUANT TO IND. CODE §§ 8-1-2-6.6, 8-1-2-6.8, CH. 8-1-8.4, CH. 8-1-8.7, CH. 8-1-8.8 AND 170 IAC 4-6-1, *ET SEQ.* AND THE COMMISSION'S ORDERS IN CAUSE NOS. 42150, 43188, 43969, 44012 AND 44311; (2) MODIFICATIONS OF AND REVISED COST ESTIMATES RESPECTING ENVIRONMENTAL COMPLIANCE PROJECTS SET FORTH IN ITS SIXTEENTH PROGRESS REPORT PURSUANT TO THE ONGOING REVIEW PROCESS UNDER IND. CODE § 8-1-8.7-7 AND APPROVED IN CAUSE NOS. 42150, 43188, 44012 AND 44311; AND MODIFICATION OF APPENDIX D – ENVIRONMENTAL COST RECOVERY MECHANISM FACTOR.	)	**CAUSE NO. 42150 ECR 26** **APPROVED:** OCT 21 2015

ORDER OF THE COMMISSION

Presiding Officers:
David E. Ziegner, Commissioner
Jeffery A. Earl, Administrative Law Judge

On July 31, 2015, Northern Indiana Public Service Company ("NIPSCO") filed is Verified Petition in this Cause. NIPSCO also prefiled the direct testimony and exhibits of the following:

- Ronald G. Plantz, Controller of NIPSCO at NiSource Corporate Services Company;
- Kurt W. Sangster, Vice President, Major Projects at NIPSCO; and
- Thomas S. Sibo; Manager, Regulatory Support and Analysis in NIPSCO's Rates and Regulatory Finance Department.

On August 6, 2015, the NIPSCO Industrial Group ("Industrial Group") filed its Petition to Intervene, which the Presiding Officers granted in a Docket Entry dated August 18, 2015.

On September 8, 2015, the Indiana Office of Utility Consumer Counselor ("OUCC") prefiled direct testimony of the following:

- Cynthia M. Armstrong, Senior Utility Analyst in the OUCC's Electric Division; and
- Wes R. Blakley, Senior Utility Analyst in the OUCC's Electric Division.

On September 11, 2015, NIPSCO filed the rebuttal testimony of Mr. Sangster.

The Commission held an evidentiary hearing in this Cause at 1:00 p.m. on September 15, 2015, in Hearing Room 224, 101 West Washington Street, Indianapolis, Indiana. NIPSCO, the OUCC, and the Industrial Group appeared at the hearing. No member of the public appeared or participated at the hearing.

Having considered the evidence presented and the applicable law, the Commission finds:

1. **Notice and Jurisdiction.** Notice of the hearing in this case was given and published by the Commission 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 §§ 8-1-2-6.6 and 8-1-2-6.8 and Ind. Code chs. 8-1-8.7 and 8-1-8.8, the Commission has jurisdiction over a public utility's cost recovery related to the use of clean coal technology. Therefore, the Commission has jurisdiction over NIPSCO and the subject matter of this case.

2. **NIPSCO's Characteristics.** Petitioner is a public utility organized and existing under Indiana law, with its principal office at 801 E. 86th Street, Merrillville, Indiana. NIPSCO owns and operates property and equipment used for the production, transmission, delivery, and furnishing of electric utility service to the public in northern Indiana.

3. **Relief Requested.** NIPSCO seeks the following relief:

- Approval of the proposed rate adjustments through its environmental cost recovery mechanism ("ECRM"), effective for bills issued during the billing cycles of November 2015 through April 2016.

- Approval of the proposed modifications to its environmental compliance projects and cost estimates detailed in its Sixteenth Progress Report.

4. **Commission Discussion and Findings Regarding ECRM.**

A. **Billing Period.** Mr. Sibo testified that consistent with Rider 672 – Adjustment of Charges for Environmental Cost Recovery Mechanism, NIPSCO requests approval of its ECRM factors to be applicable to the bills rendered during the billing cycles of November 2015 through April 2016. The ECRM factors include actual costs through June 30, 2015, and a reconciliation of projected period recoveries of ECRM revenue with actual revenue during the period November 1, 2014, through April 30, 2015.

B. **Environmental Compliance Project Investment.** Mr. Sibo testified that the total cost of Environmental Compliance Projects under construction, net of accumulated depreciation, upon which NIPSCO is authorized to earn a return is $776,542,613. The construction costs include an allowance for funds used during construction ("AFUDC"). Mr. Plantz testified that he computed the AFUDC in accordance with the FERC Uniform System of Accounts, and that will cease accruing AFUDC on those costs once such amounts are being recovered through rates.

Mr. Sibo testified that for purposes of calculating the revenue requirement associated with the Unit 7 SCR Catalyst 2nd Layer, NIPSCO followed the ratemaking treatment prescribed by the Commission in Cause No. 42150 ECR 21.

As reflected on Exhibit 1-A, Schedule 4, consistent with the Commission's October 16, 2013 Order in Cause No. 42150 ECR 21, NIPSCO has only included the incremental amount of the return on its investment for the replacement catalyst layer that exceeds the return on investment currently included in its base rates and charges for the original catalyst layer.

Mr. Sangster testified that Schedules 1, 1A, and 1B of Exhibit 1-A attached to NIPSCO's Verified Petition describe the Company's Environmental Compliance Projects under construction that have been approved by the Commission on which NIPSCO proposes to earn a return. Schedules 1, 1A, and 1B set out a brief description of the project, approved cost estimates, the construction start dates, the anticipated in-service dates, and the current and prior investment values for each project. The costs for NIPSCO's Environmental Compliance Projects have been compiled through June 30, 2015. Mr. Sangster also testified that all of the projects for which NIPSCO is seeking ratemaking treatment in this Cause have been under construction for at least six months.

Based on the evidence presented, we find that NIPSCO's request to begin earning a return on $776,542,613, the value of its Environmental Compliance Projects, net of accumulated depreciation, is reasonable, and we approve the request.

C. <u>Semi-Annual Revenue Requirement</u>. Mr. Plantz computed NIPSCO's proposed semi-annual return on its Environmental Compliance Projects at June 30, 2015, of a net amount of $37,974,466, which is the product of the value of NIPSCO's Environmental Compliance Projects multiplied by the debt and equity components of its weighted cost of capital, adjusted for taxes and multiplied by 0.50. Petitioner's Exhibit 1-A, Schedule 7 shows that NIPSCO's Adjusted Semi-Annual Revenue Requirement is $37,741,322, after including the prior period reconciliation.

Mr. Plantz sponsored the calculation of NIPSCO's 6.57% weighted cost of capital, using its full regulatory capital structure, per books, at June 30, 2015, which is the date of valuation of the Environmental Compliance Projects in accordance with 170 I.A.C. 4-6-14. The cost rates for long-term debt and preferred stock reflect the 12 months ended June 30, 2015. The cost rates for common equity capital of 10.2% and customer deposits of 4.43% are those approved by the 2011 Rate Order. Deferred taxes and the reserve for post-retirement benefits are treated as zero-cost capital and the cost of post-1970 investment tax credits reflects the weighted costs of long-term debt, preferred stock, and common equity capital. NIPSCO's weighted average cost of capital of 6.57% reflects a 4-basis-point increase from the 6.53% approved in the ECR 25 Order.

Based on the evidence presented, we find that NIPSCO's proposed Adjusted Semi-Annual Revenue Requirement of $37,741,322 is reasonable, and we approve the revenue requirement.

D. <u>Allocation of Semi-Annual Environmental Compliance Project Revenue Requirement</u>. Mr. Sibo sponsored Schedule 5 of Exhibit 1-A which shows the production allocation percentages attributable to each of NIPSCO's rate schedules. These allocation percentages, which were approved by the ECR 19 Order, are adjusted to reflect the significant migration of customers among Rates 621, 624, 625, 626, and 632. Mr. Sibo testified that this adjustment is appropriate in order to prevent any unintended consequences of the migration of customers between rates and to properly allocate their share of capital charges and that it is consistent with the adjustments most recently approved by the Commission in its ECR 25 Order.

Based on the evidence presented, we find that NIPSCO's ECRM factors have been allocated on the basis of the 12 Coincident Peak method in accordance with our ECR 19 Order.

E. Reconciliation of Prior Period Recoveries. Mr. Sibo testified that Schedule 6 of Exhibit 1-A shows NIPSCO's reconciliation of projected period recoveries of ECRM revenue with actual revenue during the period November 2014 through April 2015. NIPSCO's total computed under- or over-recoveries of ECRM revenue for this period are reflected in Column 4. Based on the evidence presented, we find that NIPSCO properly included reconciliation in its ECRM calculations.

F. New ECRM Factors. Mr. Sibo sponsored Exhibit 1-A, Attachment B (Appendix D - Environmental Cost Recovery Mechanism Factor) showing the ECRM factors applicable to the various NIPSCO rate schedules and explained how the ECRM factors were developed. Mr. Sibo also explained NIPSCO's proposed modification to Appendix D. He explained that Appendix D includes a statement that "[t]he ECRM adjustment factor for Rider 676 will be the adjustment factor associated with the appropriate firm service rate schedule, either Rate 632, 633, or 634, being used in conjunction with this Rider." Rider 676 is only available to Rate 632 or 633. In this filing, NIPSCO is proposing to remove the reference to Rate 634 from this statement.

Mr. Sibo testified that the estimated average monthly bill impact for a typical residential customer using 688 kWh per month is $4.42, which is a $0.43 increase from what a customer would pay today using the current ECRM Factors. Mr. Sibo testified that the estimated average monthly bill impact for a typical residential customer using 1,000 kWh per month will be $6.43, which is a $0.64 increase from what a customer would pay today using the current ECRM Factors. Mr. Blakley testified that nothing came to his attention that would indicate that NIPSCO's calculation of estimated ECR adjustment factors for the relevant period is unreasonable.

Based on the evidence presented, we approve the proposed ECRM factors set forth in Petitioner's Exhibit 1-A, Attachment B to be applicable for bills rendered during the billing cycles of November 2015 through April 2016.

5. Commission Findings and Conclusions Regarding Progress Report. In the 42150 Order, the Commission approved NIPSCO's proposal that the Commission maintain an ongoing review of its Environmental Compliance Project construction and expenditures and submit to the Commission annually a report of any revisions of its plan and cost estimates for such construction ("Progress Report"). In its 43526 Order, the Commission ordered NIPSCO to file its Progress Reports on the status of Environmental Compliance Projects tracked in the

ECRM as part of its ECRM filings rather than in a separate proceeding. The Phase I 44012 Order approved Petitioner's request to file semi-annual progress reports (as opposed to annual progress reports) as part of the ongoing review process under Ind. Code §8-1-8.7-7. The 44311 Order authorized NIPSCO to seek timely recovery of the MATS Compliance Plan Projects as part of NIPSCO's semi-annual progress reports filed in ECR proceedings and to provide updates to the MATS Capital Projects through its semi-annual ECRM proceedings.

NIPSCO requests approval of its Sixteenth Progress Report on the status of Environmental Compliance Projects tracked in the ECRM and approval to recover the revised costs of its Environmental Compliance Projects through the ECRM and EERM. Specifically, NIPSCO requests the Commission approve its revised Compliance Plan as set forth in Exhibit PR attached to NIPSCO's Verified Petition, including the updated project scopes, construction schedules, and cost estimates. Since the Fifteenth Progress Report, NIPSCO has identified aspects of the plan that require further modification. Mr. Sangster testified that Exhibit PR attached to NIPSCO's Verified Petition identifies and describes the plan modifications, which can be broken down into several categories: scheduling changes, additions and/or subtractions from the Compliance Plan, and changes in estimated costs.

Mr. Sangster provided an update on the status of several of the Environmental Compliance Projects. With respect to the three components of the Schahfer FGD program, Unit 14 FGD Facility Addition, Unit 14/15 FGD Common, and Unit 15 FGD Facility Addition, Mr. Sangster testified that the Unit 14 FGD Facility Addition and Unit 14/15 FGD Common facilities were successfully put into service on November 19, 2013. The Unit 15 FGD Facility Addition was successfully put into service on November 5, 2014. The Unit 14 FGD, for the 30-day rolling average for the period ending July 28, 2015, had an outlet sulfur dioxide ("SO_2") level of 0.026 lb/MMBtu. The Unit 15 FGD, for the same time period, had an outlet SO_2 level of 0.006 lb/MMBtu. Both units are operating well below the Consent Decree limit of 0.08 lb/MMBtu. The Consent Decree limit is more restrictive for SO_2than the MATS limit of 0.20 lb/MMBtu. Mr. Sangster testified that the total cost estimate for the three components of the Schahfer FGD program has not changed ($500 million total for Unit 14 FGD, Unit 15 FGD and Unit 14/15 Common Facilities).

With respect to the Michigan City Unit 12 FGD Facility Addition, Mr. Sangster testified that the Michigan City Unit 12 FGD Facility Addition project is progressing on-schedule and on budget with respect to the revisions made and approved in ECR 25. Construction began March 25, 2013. The outage in which the final tie-ins will be performed and startup will follow is scheduled to begin September 5, 2015, and complete November 30, 2015. The current estimate at completion is approximately $255,000,000 (exclusive of AFUDC) for the Unit 12 Dry FGD. The current forecast is based on the remaining work to be completed and a reduction of the projected risks and issues currently associated with the project. While risks remain with the project, NIPSCO continues to identify the risks and mitigate them before they become issues. For example, the team is currently working through the loss of approximately 40 work days due to the impact of adverse weather in 2015. While there is no cost impact to the project at this time associated with those lost days, further delays may have a financial impact on the project.

Mr. Sangster testified the Unit 14 TR Set Project completed construction and went into service on November 19, 2013. The Unit 18 TR Set Project completed construction and went into service on May 5, 2014. The Unit 15 TR Set Project completed construction and went into service on November 5, 2014. The Unit 17 TR Set Project completed construction and went into service on June 1, 2015. The construction start date and the in-service date for Unit 17, as shown on Exhibit PR, was changed to reflect actual dates.

Mr. Sangster testified that the Units 7, 8, 12, 14, and 15 ACI projects are progressing on schedule and budget. The Units 7 and 8 ACI System was commissioned on January 16, 2015. The Unit 15 ACI System was commissioned on May 22, 2015. The Unit 14 ACI System is estimated to be commissioned on July 31, 2015. The Unit 12 ACI System is currently under construction with the silo and building set, commissioning is expected to occur after the Unit 12 FGD has been put into service, tuned and tested, which is projected to occur around March 31, 2016.

Mr. Sangster testified that the chemical skids for the Fuel Additive projects for Units 7, 8, 12, 14, and 15 are currently being fabricated, with delivery expected the beginning of August 2015. Construction is expected to start the beginning of August 2015 for the Unit 12 Fuel Additive Project, late August 2015 for Units 14 and 15 and mid-September 2015 for Units 7 and 8. As with the Unit 12 ACI project, the Unit 12 Fuel Additive Project will start up after the FGD system has been put into service, tuned and tested which is projected to occur around March 31, 2016. The Unit 7, Unit 8, Unit 14, and Unit 15 will start-up and begin testing of the system in the Fall of 2015.

Mr. Sangster testified the construction start and in service date for the Unit 12 SCR Catalyst 1st Layer, the Unit 14 SCR Catalyst 1st Layer, the Unit 12 Fuel Additive and the Unit 15 ESP Flow Modification projects were revised to reflect the current schedule. The construction start date and the in service date for Unit 17 TR Set project were revised to reflect the actual dates. Unit 7 ACI System, Unit 8 ACI System and the Unit 15 ACI System projects were updated to reflect the actual in service dates. The Unit 12 ACI System and the Unit 14 ACI System in service dates were updated to reflect the current schedule. The Unit 7 Fuel Additive, Unit 8 Fuel Additive, U14 Fuel Additive, and Unit 15 Fuel Additive project construction start dates were revised to reflect the current schedule. Based on our review of the evidence, we find that NIPSCO's proposed scheduling changes are reasonable.

Mr. Sangster testified that NIPSCO is proposing to recover the cost of purchasing six Thermo 84I permeation sources to enable the ongoing calibration and certification of NIPSCO's Continuous Mercury Monitoring systems ("CMMS"). The Environmental Protection Agency requires utilities to follow manufacturer recommendations for quality assurance in order to maintain the continued certification of the CMMS. According to the manufacturer of the CMMS, using a permeation source is an acceptable way to verify the calibrator output and maintain the certification of the CMMS.

Mr. Sangster testified NIPSCO learned of this additional compliance option in February 2015 when the manufacturer commercially released the method at the Energy, Utility, and Environmental Conference. He said that NIPSCO considered two additional ways to verify the calibrator output and maintain the certification of the CMMS. The first would be to remove the calibrators annually and ship them back to the manufacturer to be checked. However, valid mercury emission data could not be collected while the calibrators were being checked. The second would be to have the manufacturer bring a vendor primed calibrator out to the sites to field certify the calibrators annually. Both are acceptable and compliant with the manufacturer's recommendations.

Mr. Sangster testified NIPSCO evaluated the alternatives and concluded that purchasing the permeation sources would be the most cost-effective method and would maximize data availability. The cost to remove and send back the six calibrators annually to be factory certified, combined with the additional equipment necessary to conduct routine sorbent trap verification checks, would exceed the cost of purchasing the permeation sources. The cost to have a field service representative on site to calibrator annually, combined with the additional equipment necessary to conduct routine sorbent trap verification checks, would exceed the cost of purchasing the permeation source. The sorbent trap verification check system is more expensive than the permeation sources. Using the permeation sources will reduce the required frequency for the manufacturer's vendor prime certification from annual to biennial.

Mr. Sangster testified that NIPSCO is only requesting the authority to recover the costs associated with the permeation sources in this proceeding. The detail relating to the permeation sources has been added to Attachment PR. He said the approximate cost is $80,000 for the six systems required for MATS reporting and compliance. NIPSCO plans to coordinate the installation of the permeation sources with the certification of the CMMS.

Ms. Armstrong testified that the OUCC does not oppose the approval of the six permeation sources. The OUCC has reviewed these projects and determined that they are additional projects that were not included in rate base and are necessary to certify the CMMS as part of the MATS requirements. She noted that these projects will also cost less than the other annual certification options for the CMMS, even when O&M costs are taken into account.

Based on our review of the evidence, we find that NIPSCO's proposal to recover the costs associated with the permeation sources is reasonable, and we authorize NIPSCO to recover the costs associated with the six permeation sources.

Ms. Armstrong said that the OUCC recommends that NIPSCO provide an explanation of whether it expects Unit 15 to meet MATS without the ESP Flow Modifications or if it expects to incur any penalties for failing to meet MATS by the April 2016 deadline.

In his rebuttal testimony, Mr. Sangster addressed Ms. Armstrong's concerns and testified that NIPSCO intends to comply with the mercury and particulate emission limitations set forth under MATS by the compliance date of April 16, 2016. NIPSCO obtained an extension for Unit 15 for the MATS mercury compliance until April 16, 2016. On Unit 15 at the Schahfer Generating Station, NIPSCO will be able to comply with the mercury removal portion of the MATS decree by injecting additional activated carbon into the flue gas. The Unit 15 ESP Flow Modification project will result in a more efficient distribution of activated carbon and less activated carbon will be required in the future for the same amount of removal once the Unit 15 ESP Flow Modification project is completed. The activated carbon Injection project was completed on Unit 15 in May of this year.

Mr. Sangster testified that NIPSCO will be able to comply with the particulate matter reduction portion of the MATS decree on Unit 15 with the upgraded High Frequency Transformer Rectifier ("TR") Sets that were installed in 2014. Currently, the Unit 15 ESP, with the High Frequency TR Sets, is operating within the MATS particulate matter emissions limits. The Unit 15 ESP Flow Modification project is expected to result in a more efficient distribution of flow across the ESP and therefore will improve the removal efficiencies of the High Frequency TR Sets.

Mr. Sangster explained that NIPSCO originally planned to complete the Flow Modification project in 2014. This would have corresponded to the same time the TR Set project and the injection lances for the activated carbon injection were also being installed on the Unit 15 ESP. It was decided at that time that due to overriding safety issues and concerns created by the amount of work all occurring in the same area, NIPSCO would delay the Unit 15 ESP Flow Modifications until the next planned outage. NIPSCO is planning to complete the ESP Flow Modification project during the next planned Unit 15 outage in the Spring 2017. He explained that the delay until the next scheduled outage will result in a safer, less congested project and will not impact NIPSCO's ability to comply with the applicable emissions limitations.

With respect to the proposed changes in estimated costs, Mr. Sangster testified Exhibit PR reflects the costs for the Unit 7 SCR Catalyst 2nd Layer and the Continuous Particulate Monitors Addition (Unit 14) projects that were completed and closed. Both projects were completed under budget. The Unit 7 SCR Catalyst 2nd Layer Project has been revised to reflect an actual spend of $855,237, which is $544,763 under the approved budget of $1,400,000. The Continuous Particulate Monitors Addition (U14) Project has been revised to reflect and actual spend of $209,316, which is $165,684 under the approved budget of $375,000. The final cost for the Unit 14 Economizer Waterside Bypass has been revised to reflect an actual spend of $4,323,273, which is a decrease of $1,622 due to a credit to the project. The Unit 12 FGD Facility Addition has been revised to reflect the current estimate at completion of $255,000,000.

Based on our review of the evidence, we find that NIPSCO's proposed changes in estimated costs are reasonable, and we approve the proposed changes and the associated estimated costs.

Mr. Sangster testified that the total cost estimate approved in the Fifteenth Progress Report was $869,073,604 for the Compliance Plan Capital projects and $2,225,000 for the MATS O&M Projects. Mr. Sangster testified the proposed revised total cost estimate for all Compliance Plan projects is $858,941,535, which is a decrease of $10,132,069. The total cost estimate of the MATS O&M Projects did not change.

As part of its Fifteenth Progress Report, NIPSCO is requesting approval of its updated Environmental Compliance Projects cost estimate of $858,941,535 and approval to recover these costs through the ECRM and EERM.

Based on the evidence presented and the foregoing discussion, we find that the Sixteenth Progress Report is reasonable. Therefore, we approve the modifications to schedule, additions and / or subtractions, and cost estimates contained therein, and we authorize NIPSCO to recover these costs through its ECRM and EERM.

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

1. NIPSCO is authorized to reflect the additional values of Environmental Compliance Projects identified herein in its rates and charges for electric service in accordance with NIPSCO's ECRM beginning with the November 2015 billing cycle.

2. Petitioner shall file with the Electricity Division of the Commission, prior to placing in effect the ECRM factors 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.

3. NIPSCO is hereby authorized to defer 20% of the federally mandated costs incurred in connection with the federally mandated MATS O&M Projects and recover those deferred costs in its next general rate case and NIPSCO is authorized to record ongoing carrying charges based on the current overall weighted average cost of capital on all deferred federally mandated costs until the deferred federally mandated costs are included for recovery in NIPSCO's base rates in its next general rate case.

4. Pursuant to Ind. Code § 8-1-8.7-7 and as approved in Cause Nos. 44311, NIPSCO's modified Compliance Plan, as set forth in the Fifteenth Report, is approved.

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

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

APPROVED: OCT 21 2015

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

ORIGINAL

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY FOR APPROVAL OF: (1) AN ADJUSTMENT TO ITS ELECTRIC SERVICE RATES THROUGH ITS ENVIRONMENTAL COST RECOVERY MECHANISM FACTOR AND ENVIRONMENTAL EXPENSE RECOVERY MECHANISM FACTOR PURSUANT TO IND. CODE §§ 8-1-2-6.6, 8-1-2-6.8, CH. 8-1-8.4, CH. 8-1-8.7, CH. 8-1-8.8 AND 170 IAC 4-6-1, *ET SEQ.* AND THE COMMISSION'S ORDERS IN CAUSE NOS. 42150, 43188, 43969, 44012 AND 44311; AND (2) MODIFICATIONS OF AND REVISED COST ESTIMATES RESPECTING ENVIRONMENTAL COMPLIANCE PROJECTS SET FORTH IN ITS SEVENTEENTH PROGRESS REPORT PURSUANT TO THE ONGOING REVIEW PROCESS UNDER IND. CODE § 8-1-8.7-7 AND APPROVED IN CAUSE NOS. 42150, 43188, 44012 AND 44311; AND MODIFICATION OF APPENDIX E – ENVIRONMENTAL EXPENSE RECOVERY MECHANISM FACTOR.	)	**CAUSE NO. 42150 ECR 27** **APPROVED:** APR 20 2016

ORDER OF THE COMMISSION

Presiding Officers:
David E. Ziegner, Commissioner
Jeffery A. Earl, Administrative Law Judge

On January 29, 2016, Northern Indiana Public Service Company ("NIPSCO") filed is Verified Petition in this Cause. NIPSCO also prefiled the direct testimony and attachments of the following witnesses:

- Thomas S. Sibo; Manager, Regulatory Support and Analysis in NIPSCO's Rates and Regulatory Finance Department; and
- Kurt W. Sangster, Vice President, Projects and Construction Electric at NIPSCO; and
- Anthony L. Sayers, General Manager, Generation at NIPSCO.

On February 4, 2016, the NIPSCO Industrial Group ("Industrial Group") filed its Petition to Intervene, which the Presiding Officers granted in a Docket Entry dated February 19, 2016.

On March 23, 2016, the Indiana Office of Utility Consumer Counselor ("OUCC") prefiled direct testimony of Wes R. Blakley, Senior Utility Analyst in the OUCC's Electric Division.

The Commission held an evidentiary hearing in this Cause at 10:00 a.m. on April 6, 2016, in Hearing Room 224, 101 West Washington Street, Indianapolis, Indiana. NIPSCO, the OUCC and the Industrial Group appeared at the hearing. No member of the public appeared or participated at the hearing.

Having considered the evidence presented and the applicable law, the Commission finds:

1. Notice and Jurisdiction. Notice of the hearing in this case was given and published by the Commission as required by law. NIPSCO is a *public utility* as defined in Ind. Code § 8-1-2-1(a). Under Ind. Code §§ 8-1-2-6.6 and 8-1-2-6.8 and Ind. Code chs. 8-1-8.7 and 8-1-8.8, the Commission has jurisdiction over a public utility's cost recovery related to the use of clean coal technology. Therefore, the Commission has jurisdiction over NIPSCO and the subject matter of this case.

2. NIPSCO's Characteristics. Petitioner is a public utility organized and existing under Indiana law, with its principal office at 801 E. 86th Street, Merrillville, Indiana 46410. NIPSCO owns and operates property and equipment used for the production, transmission, delivery, and furnishing of electric utility service to the public in northern Indiana.

3. Relief Requested. NIPSCO seeks the following relief:

- Approval of the proposed rate adjustments through its environmental cost recovery mechanism ("ECRM"), effective for bills issued during the billing cycles of May through October 2016.
- Approval of the proposed rate adjustments through its environmental expense recovery mechanism ("EERM"), effective for bills issued during the billing cycles of May 2016 through April 2017.
- Approval of the proposed modifications to its environmental compliance projects and cost estimates detailed in its Seventeenth Progress Report.

4. Commission Discussion and Findings Regarding ECRM.

A. Billing Period. Mr. Sibo testified that consistent with Rider 672 – Adjustment of Charges for Environmental Cost Recovery Mechanism, NIPSCO requests approval of its ECRM factors to be applicable to the bills rendered during the billing cycles of May through October 2016. The ECRM factors include actual costs through December 31, 2015, and a reconciliation of projected period recoveries of ECRM revenue with actual revenue during the period May through October 2015.

B. Environmental Compliance Project Investment. Mr. Sibo testified that the total cost of Environmental Compliance Projects under construction, net of accumulated depreciation, upon which NIPSCO is authorized to earn a return is $800,748,752. He testified that the construction costs include an allowance for funds used during construction ("AFUDC"), computed in accordance with the Federal Energy Regulatory Commission Uniform System of Accounts. Mr. Sibo testified that if the Commission approves the proposed ratemaking treatment for the values shown on Petitioner's Exh. 1, Attachment A, Schedule 1B, NIPSCO will cease accruing AFUDC on those costs once such amounts are being recovered through rates.

Mr. Sibo testified that for purposes of calculating the revenue requirement associated with the Unit 7 SCR Catalyst 2nd Layer, NIPSCO followed the ratemaking treatment prescribed by the Commission in Cause No. 42150 ECR 21. As reflected on Petitioner's Exh. 1, Attachment A, Schedule 4, NIPSCO has only included the incremental amount of the return on its investment for the replacement catalyst layer that exceeds the return on investment currently included in its base rates and charges for the original catalyst layer.

Mr. Sangster testified that Petitioner's Exh. 1, Attachment A, Schedules 1, 1A, and 1B describe the Company's Environmental Compliance Projects under construction which have been approved by the Commission and on which NIPSCO proposes to earn a return. Schedules 1, 1A, and 1B set out a brief description of the project, approved cost estimates, the construction start dates, the anticipated in-service dates, and the current and prior investment values for each project. The costs for NIPSCO's Environmental Compliance Projects have been compiled through December 31, 2015. Mr. Sangster also testified that all of the projects for which NIPSCO is seeking ratemaking treatment in this Cause have been under construction for at least six months.

Based on the evidence presented, we find that NIPSCO's request to begin earning a return on $800,748,752, the value of its Environmental Compliance Projects, net of accumulated depreciation, is reasonable and we approve the request.

C. <u>Semi-Annual Revenue Requirement</u>. Mr. Sibo computed NIPSCO's proposed semi-annual return on its Environmental Compliance Projects at December 31, 2015, of a net amount of $38,822,445, which is the product of the value of NIPSCO's Environmental Compliance Projects multiplied by the debt and equity components of its weighted cost of capital, adjusted for taxes and multiplied by 0.50. Schedule 7 shows that NIPSCO's Adjusted Semi-Annual Revenue Requirement is $40,212,582 after including the prior period reconciliation.

Mr. Sibo sponsored the calculation of NIPSCO's 6.49% weighted cost of capital, using its full regulatory capital structure, per books, at December 31, 2015, which is the date of valuation of the Environmental Compliance Projects in accordance with 170 I.A.C. 4-6-14. He testified the cost rates for long-term debt and preferred stock reflect the 12 months ended December 31, 2015. He also testified the cost rates for common equity capital of 10.2% and customer deposits of 4.43% are those approved by the 2011 Rate Order. He testified that deferred taxes and the reserve for post-retirement benefits are treated as zero-cost capital and the cost of post-1970 investment tax credits reflects the weighted costs of long-term debt, preferred stock, and common equity capital. Mr. Sibo testified that NIPSCO's weighted average cost of capital of 6.49% reflects an 8-basis-point decrease from the 6.57% approved in the ECR 26 Order.

Based on the evidence presented, we find that NIPSCO's proposed Adjusted Semi-Annual Revenue Requirement of $40,212,582 is reasonable, and we approve the revenue requirement.

D. <u>Allocation of Semi-Annual Environmental Compliance Project Revenue Requirement</u>. Mr. Sibo sponsored Petitioner's Exh. 1, Attachment A, Schedule 5, which shows the production allocation percentages attributable to each of NIPSCO's rate schedules. These allocation percentages, which were approved by the ECR 19 Order, are adjusted to reflect the significant migration of customers among Rates 621, 624, 625, 626, and 632. Mr. Sibo testified that this adjustment is appropriate in order to prevent any unintended consequences of the migration of customers between rates and to properly allocate their share of capital charges and is consistent with the adjustments most recently approved by the Commission in its ECR 26 Order.

Based on the evidence presented, we find that NIPSCO's ECRM factors have been allocated on the basis of the 12 Coincident Peak ("CP") method in accordance with our ECR 19 Order.

E. <u>**Reconciliation of Prior Period Recoveries.**</u> Mr. Sibo testified that Petitioner's Exh. 1, Attachment A, Schedule 6 shows NIPSCO's reconciliation of projected period recoveries of ECRM revenue with actual revenue during the period May through October 2015. NIPSCO's total computed under- or over-recoveries of ECRM revenue for this period are reflected in Column 4. Based on the evidence presented, we find that NIPSCO properly included reconciliation in its ECRM calculations.

F. <u>**New ECRM Factors.**</u> Mr. Sibo sponsored Petitioner's Exh. 1-A, Attachment B (Appendix D - Environmental Cost Recovery Mechanism Factor) showing the ECRM factors applicable to the various NIPSCO rate schedules and explained how the ECRM factors were developed. Mr. Sibo testified that the estimated average monthly bill impact for a typical residential customer using 688 kWh per month is $4.14, which is a $0.28 decrease from what a customer would pay today using the current ECRM Factors. Mr. Sibo testified that the estimated average monthly bill impact for a typical residential customer using 1,000 kWh per month will be $6.02, which is a $0.41 decrease from what a customer would pay today using the current ECRM Factors. Mr. Blakley testified that nothing came to his attention that would indicate that NIPSCO's calculation of estimated ECR adjustment factors for the relevant period is unreasonable.

Based on the evidence presented, we approve the proposed ECRM factors set forth in Petitioner's Exh. 1-A, Attachment B to be applicable for bills rendered during the billing cycles of May through October 2016.

5. <u>**Commission Findings and Conclusions Regarding EERM.**</u>

A. <u>**Relevant Period**</u>. Mr. Sibo testified that consistent with Rider 673 – Adjustment of Charges for Environmental Expense Recovery Mechanism, NIPSCO requests authority to recover operating, maintenance and depreciation expenses in connection with the operation of its Environmental Compliance Projects that were in service during the 12 months ended December 31, 2015, and the recoverable portion (80%) of the MATS Compliance Plan O&M Project expenses incurred through December 31, 2015, through its EERM factors to be applicable for bills rendered during the billing cycles of May 2016 through April 2017.

B. <u>**Actual O&M Expense**</u>. Mr. Sayers testified that as shown on Petitioner's Exh. 1-A, Attachment C, Schedule 1-EERM, Page 2 of 2, for the twelve months ending December 31, 2015, NIPSCO incurred $10,495,039 of Actual O&M Expense associated with NIPSCO's Environmental Compliance Projects (capital projects) and recoverable federally mandated MATS O&M Project expenses, of which $449,228 was fixed and $10,045,811 was variable.

1. <u>**Environmental Compliance Projects**</u>. Mr. Sayers testified that a total of $10,495,039 O&M expense was incurred related to Environmental Compliance Projects

in service as shown on Petitioner's Exh. 1-A, Attachment C, Schedule 1-EERM, Page 2 of 2. Mr. Sayers listed the Environmental Compliance Projects that were in service during the period from January 1 through December, 2015, and explained whether NIPSCO incurred any O&M expenses associated with those projects.

Mr. Sayers testified that O&M expenses for the twelve months ending December 31, 2015, increased from actual expenses incurred during the twelve months ending December 31, 2014, primarily because more Environmental Compliance Projects were in service in 2015 than in 2014. Most notably, the Unit 15 FGD project was in service and incurred operating expenses for a full year in 2015 as compared to only approximately one month in 2014. In addition, Mr. Sayers explained a few MATS ACI projects went into service in 2015 along with the Unit 12 FGD going into service at the end of 2015. Finally, Mr. Sayers testified that there were no noteworthy increases in O&M expenses in 2015, identified and explained new O&M expense categories created since the O&M expenses were approved in the ECR 25 Order, and summarized his expectations regarding the O&M expenses associated with NIPSCO's ownership and operation of the Environmental Compliance Projects that will be in service during the period from January 1, 2016, through December 31, 2016.

2. <u>MATS Projects</u>. Mr. Sayers testified that in the 44311 Order, the Commission approved the following federally mandated O&M Projects as part of NIPSCO's MATS Compliance Plan: (1) Precipitator & FGD Mist Eliminator Cleaning for Bailly Units 7 & 8; (2) Schahfer Unit 15 ESP Flow Modeling; and (3) Air Testing for Schahfer Units 14, 15, 17, 18. He described the Precipitator & FGD Mist Eliminator Cleaning for Bailly Units 7 & 8 approved as part of the MATS Compliance Plan in Cause No. 44311 and testified that as shown on Petitioner's Exh. 1-A, Attachment C, Schedule 1A-EERM, NIPSCO incurred $333,333 related to Bailly Units 7 & 8 during 2015, $84,508 related to Unit 7 and $248,825 related to Unit 8. Mr. Sayers described the federally mandated Schahfer Unit 15 ESP Flow Modeling Project approved as part of the MATS Compliance Plan in Cause No. 44311 and testified that NIPSCO did not incur any expenses associated with that project.

Mr. Sayers described the federally mandated O&M Project Unit 15 ESP Flow Modifications approved as part of the Fourteenth Progress Report in Cause No. 42150 ECR 24 and testified that although this work was originally scheduled for the Fall 2014 outage, this work was not completed during that outage because of congestion inside the ESP due to normal outage work, duct work repairs, and the installation of the Unit 15 TR Sets Project. The work is now scheduled to be completed during the 2017 spring outage. He testified that NIPSCO has followed up with preliminary construction estimates for the installation of the modifications suggested in the Unit 15 Flow Model study. He testified that the preliminary installation estimates have seen increases from the original estimate of $650,000 approved in the Fourteenth Progress Report. He testified that NIPSCO will continue to refine the estimate to have better information to share in its next filing. Mr. Sayers described the federally mandated O&M Project Air Testing for Schahfer Units 14, 15, 17, 18 approved as part of the MATS Compliance Plan in Cause No. 44311 and testified that NIPSCO did not incur any expenses associated with those projects.

Mr. Sibo testified that Petitioner's Exh. 1, Attachment C, Schedule 1A-EERM shows the detail of all expenses incurred in conjunction with NIPSCO's federally mandated MATS Compliance Plan O&M Projects. In accordance with the 44311 Order, NIPSCO may recover 80%

of all costs associated with approved federally mandated MATS O&M projects through the currently-effective EERM tracking mechanism.

Based on the evidence presented, we find that NIPSCO's Actual O&M Expense associated with NIPSCO's Environmental Compliance Projects (capital projects) and recoverable federally mandated MATS O&M Project expenses for the period ending December 31, 2015, of $10,495,039 are reasonable and approve recovery through the EERM factors beginning with the May 2016 billing cycle.

C. Actual Depreciation Expense. Petitioner's Exh. 1, Attachment C, Schedule 1-EERM, page 1 of 2, shows that NIPSCO's actual depreciation expense for the twelve months ending December 31, 2015 was $29,052,708. Mr. Sibo testified that the Actual Depreciation Expense consists of depreciation expenses incurred in the period January through December 2015 associated with NIPSCO's ownership and operation of the Environmental Compliance Projects that have been placed in service. He testified that Actual Depreciation Expense was computed based on the depreciation lives and/or rates approved in Cause Nos. 42150, 43188, 44012 and 44311.

Based on the evidence presented, we find that NIPSCO's Actual Depreciation Expense for the period ending December 31, 2015, of $29,052,708 has been properly calculated and is reasonable. Therefore, we approve the Actual Depreciation Expense for recovery through the EERM factors beginning with the May 2016 billing cycle.

D. Allocation of Actual O&M and Depreciation Expenses. Mr. Sibo testified that the part of the EERM charge for operating and maintenance expenses is determined by multiplying the operating and maintenance expenses proposed for recovery times the composite percentage of two elements: (1) an element for the production allocation percentage, which is used for fixed operating and maintenance expenses, and (2) an element for the energy allocation percentages, which is used for variable operating and maintenance expenses.

Mr. Sibo explained NIPSCO's proposed adjustments to its production allocation percentages. He testified that NIPSCO has adjusted its production allocation percentages to reflect the significant migration of customers amongst Rates 621, 624, 625, 626, and 632. He explained that this migration was based upon the customers' 12 CP calculated in conjunction with the approved allocators in Joint Exh. E to the Stipulation and Settlement Agreement approved in the 2011 Rate Order. Mr. Sibo testified that this adjustment is appropriate in order to prevent any unintended consequences of the migration of customers between rates and to properly allocate their share of capital charges and is consistent with the adjustments most recently approved by the Commission in its ECR 25 Order.

Mr. Sibo also explained NIPSCO's proposed adjustments to its energy allocation percentages. He testified that NIPSCO has adjusted its energy allocation percentages to reflect the significant migration of customers amongst Rates 621, 624, 625, 626, and 632. He explained that this migration was based on the customers' test year sales for the 12 months ending June 30, 2010 from Cause No. 43969, adjusted for system losses. Mr. Sibo testified this adjustment is appropriate in order to prevent any unintended consequences of the migration of customers to different rate classes and to properly allocate their share of EERM charges and is consistent with the adjustments most recently approved by the Commission in its ECR 25 Order.

Based on the evidence presented, we find that NIPSCO's proposed EERM factors have been properly allocated on the basis of Joint Exh. E to the 2011 Settlement – the 12 CP method in accordance with our ECR 19 Order. We also find that NIPSCO has properly allocated the depreciation portion of EERM costs and the fixed portion of the O&M component of EERM costs on the same basis as the production allocation utilized for the capital costs inside of the ECRM (i.e. the Joint Exh. E Allocation or 12 CP in accordance with our ECR-19 Order). Finally, we find that NIPSCO properly allocated the variable O&M expenses to classes based on test year sales for the twelve months ending June 30, 2010 from Cause No. 43969, adjusted for system losses.

E. **Reconciliation of Projected Period Recoveries.** Mr. Sibo testified that Petitioner's Exh. 1, Attachment C, Schedule 2-EERM shows the Company's reconciliation of projected period recoveries of EERM revenue with actual revenue during the period from May 1, 2014, to April 30, 2015. He explained that since NIPSCO's EERM factors approved in Cause No. 42150 ECR 23 ended April 30, 2015, NIPSCO is able to compute any under- or over- recoveries of EERM revenue, which are reflected in Column 4. Based on the evidence presented, we find that NIPSCO properly included a reconciliation of projected period recoveries for recovery through the EERM factors beginning with the May 2016 billing cycle.

F. **New EERM Factors.** Mr. Sibo sponsored Petitioner's Exh. 1-A, Attachment D (Appendix E - Environmental Expense Recovery Mechanism Factor) showing the EERM factors applicable to the various NIPSCO rate schedules and explained how the EERM factors were developed. Mr. Sibo also sponsored Petitioner's Exh. 1, Attachment C, Schedule 1-EERM which shows that calculation underlying the proposed EERM factors. Mr. Sibo testified that the estimated average monthly bill impact for a typical residential customer using 688 kWh per month is $2.12, which is a $0.50 increase from what a customer would pay today using the current EERM Factors. Mr. Sibo testified that the estimated average monthly bill impact for a typical residential customer using 1,000 kWh per month will be $3.08, which is a $0.73 increase from what a customer would pay today using the current EERM Factors.

Based on the evidence presented, we approve the proposed EERM factors set forth in Petitioner's Exh. 1-A, Attachment D to be applicable for bills rendered during the billing cycles of May 2016 through April 2017.

G. **Deferred Federally Mandated Costs.** Mr. Sibo testified that Petitioner's Exh. 1, Attachment C, Schedule 1A-EERM shows the detail of all expenses incurred in conjunction with NIPSCO's federally mandated MATS Compliance Plan O&M Projects. He testified that in accordance with the 44311 Order and Ind. Code § 8-1-8.4-7(c), NIPSCO will defer, as a regulatory asset on the balance sheet, 20% of all costs associated with approved federally mandated MATS Compliance Plan O&M Project, including post in-service carrying charges on the deferred O&M expenses, for recovery in NIPSCO's next general rate case. Petitioner's Exh. 1, Attachment C, Schedule 3-EERM provides a record of the deferred federally mandated costs as well the ongoing carrying charges on all deferred federally mandated costs until such time as the costs can be recovered as part of NIPSCO's next general rate case.

Based on the evidence presented and pursuant to the 44311 Order and Ind. Code § 8-1-8.4-7(c)(2), we authorize NIPSCO to defer 20% of the federally mandated costs incurred in connection with the federally mandated MATS O&M Projects and recover those deferred costs in its next general rate case. In addition, we authorize NIPSCO to record ongoing carrying charges based on the current overall weighted average cost of capital on all deferred federally mandated costs until the deferred federally mandated costs are included for recovery in NIPSCO's base rates in its next general rate case as allowed by Ind. Code § 8-1-8.4-7(c)(2).

6. Commission Findings and Conclusions Regarding Progress Report. In the 42150 Order, the Commission approved NIPSCO's proposal that the Commission maintain an ongoing review of its Environmental Compliance Project construction and expenditures and submit to the Commission annually a report of any revisions of its plan and cost estimates for such construction ("Progress Report"). In its 43526 Order, the Commission ordered NIPSCO to file its Progress Reports on the status of Environmental Compliance Projects tracked in the ECRM as part of its ECRM filings rather than in a separate proceeding. The Phase I 44012 Order approved Petitioner's request to file semi-annual progress reports (as opposed to annual progress reports) as part of the ongoing review process under Ind. Code § 8-1-8.7-7. The 44311 Order authorized NIPSCO to seek timely recovery of the MATS Compliance Plan Projects as part of NIPSCO's semi-annual progress reports filed in ECR proceedings and to provide updates to the MATS Capital Projects through its semi-annual ECRM proceedings.

Pursuant to the ongoing review process under Ind. Code §8-1-8.7-7 and as approved in the 44311 Order, in this proceeding NIPSCO requests approval of its Seventeenth Progress Report on the status of Environmental Compliance Projects tracked in the ECRM and approval to recover the revised costs of its Environmental Compliance Projects through the ECRM and EERM. Specifically, NIPSCO requests the Commission approve its revised Compliance Plan as set forth in Attachment PR attached to NIPSCO's Verified Petition initiating this Cause, including the updated project scopes, construction schedules, and cost estimates described therein. Since the Sixteenth Progress Report, NIPSCO has identified aspects of the plan that require further modification. Mr. Sangster testified that Attachment PR attached to NIPSCO's Verified Petition initiating this Cause identifies and describes the plan modifications which can be broken down into several categories: scheduling changes, additions and/or subtractions from the Compliance Plan, and changes in estimated costs.

Mr. Sangster provided an update on the status of several of the Environmental Compliance Projects. With respect to the three components of the Schahfer FGD program, Unit 14 FGD Facility Addition, Unit 14/15 FGD Common, and Unit 15 FGD Facility Addition, Mr. Sangster testified that the Unit 14 FGD Facility Addition and Unit 14/15 FGD Common facilities were successfully put into service on November 19, 2013. He testified that the Unit 15 FGD Facility Addition was successfully put into service on November 5, 2014. For the Unit 14 FGD, the 2015 average outlet SO2 level was 0.014 lbs./MMBtu and the Unit 15 FGD outlet SO2 level was 0.011 lbs./MMBtu. Both units are operating well below the Consent Decree limit of 0.08 lbs./MMBtu. The Consent Decree limit is more restrictive for SO_2 than the MATS limit of 0.20 lbs./MMBtu. Mr. Sangster testified that the total cost estimate for the three components of the Schahfer FGD program has not changed ($500 million total for Unit 14 FGD, Unit 15 FGD and Unit 14/15 Common Facilities).

With respect to the Michigan City Unit 12 FGD Facility Addition, Mr. Sangster testified that the Michigan City Unit 12 FGD Facility Addition project was successfully put into service on December 15, 2015 and is currently undergoing commissioning, tuning, and performance testing, so SO_2 emissions data is not yet available. He testified that the project is progressing on budget with respect to the revisions made and approved in ECR-25. Mr. Sangster testified consistent with the 44012 Phase III Order, NIPSCO has been providing the OUCC and Industrial Group on a monthly basis since March of 2013, with a weekly project status report, monthly project report, and senior executive project reports, relating to the Michigan City Unit 12 FGD Facility Addition. He testified that these reports also contained NIPSCO's monthly risk assessment relating to the Unit 12 FGD Facility Addition. Also consistent with the 44012 Phase III Order, NIPSCO extended an open invitation to the OUCC and Industrial Group to attend NIPSCO's recurring (usually monthly) project meeting held on-site at the Michigan City Generation Station. Several OUCC staff members periodically attended these meetings. Mr. Sangster testified that since construction is complete and the Unit 12 FGD Facility Addition has gone into service, NIPSCO will no longer produce the three separate reports referenced above and will no longer hold the monthly project meetings. He testified that in light of the foregoing, NIPSCO believes there are no further reporting activities associated with the Unit 12 FGD Facility Addition.

Mr. Sangster testified the Unit 14 TR Set Project completed construction and went into service on November 19, 2013. The Unit 15 TR Set Project completed construction and went into service on November 5, 2014. The Unit 17 TR Set Project completed construction and went into service on June 1, 2015. The Unit 18 TR Set Project completed construction and went into service on May 5, 2014. He testified that NIPSCO currently expects the TR Set Project to be under budget by approximately $2,000,000.

Mr. Sangster testified the Units 7, 8, 12, 14 and 15 ACI projects are progressing on schedule and under budget. The Units 7 and 8 ACI System was commissioned on January 16, 2015. The Unit 12 ACI System is mechanically complete, commissioning is expected to occur after the Unit 12 FGD has been put into service, tuned and tested, which is projected to occur around March 31, 2016. The Unit 14 ACI System was commissioned on July 31, 2015. The Unit 15 ACI System was commissioned on May 22, 2015. He testified that NIPSCO currently expects the ACI Project to be under budget by approximately $6,000,000.

Mr. Sangster testified that the Units 7 and 8 Fuel Additive project was commissioned on December 8, 2015. The Unit 12 Fuel Additive project is mechanically complete, commissioning is expected to occur after the Unit 12 FGD has been put into service, tuned and tested, which is projected to occur around March 31, 2016. The Unit 14 and Unit 15 Fuel Additive projects were commissioned on December 10, 2015.

Mr. Sangster testified that the Permeation Source for Unit 17 installation was completed on June 23, 2015. The Units 7/8, 14 and 15 Permeation Sources were installed and put in service July 30, 2015. The Unit 12 Permeation Source was installed and put in service July 31, 2015. The Permeation Source for Unit 18 was installed and put in service on August 13, 2015.

As to the scheduling changes, Mr. Sangster testified the construction start for the Unit 17 SCR Catalyst 3rd Layer was revised to reflect the current schedule. The construction start date for the Unit 12 Fuel Additive project was revised to reflect the actual date. The Unit 12 FGD Facility

Addition was revised to reflect the actual in-service date. The Unit 7 Fuel Additive, Unit 8 Fuel Additive, Unit 14 Fuel Additive, Unit 15 Fuel Additive, Unit 17 Fuel Additive, Unit 18 Fuel Additive, Permeation Source Unit 7/8, Permeation Source Unit 12, Permeation Source Unit 14, Permeation Source Unit 15, Permeation Source Unit 17 and Permeation Source Unit 18 projects were all revised to reflect the actual construction start and actual in-service dates. The dates for the Unit 12 Economizer Waterside Bypass were removed to reflect the project cancellation that was communicated in ECR025. Based on our review of the evidence, we find that NIPSCO's proposed scheduling changes are reasonable and should be approved.

With respect to the proposed changes in estimated costs, Mr. Sangster testified the final project costs for the Unit 8 SCR Catalyst 4th Layer has been revised to reflect an actual spend of \$1,316,938, which is \$433,062 under the approved budget of \$1,750,000. The Continuous Particulate Monitors Addition (Unit 14) project which was closed in ECR 26 has been adjusted for a charge of \$1,409 that was miscoded, the budget now reflects the final costs. The project costs for the Unit 17 TR Sets have been reduced to \$3,187,350, the Unit 18 TR Sets have been reduced to \$3,187,350, the Unit 7 ACI System has been reduced to \$3,136,402, the Unit 8 ACI System has been reduced to \$4,262,918, the Unit 12 ACTI System has been reduced to \$4,614,280, the Unit 14 ACI System has been reduced to \$4,614,850, the Unit 15 ACI System has been reduced to \$5,114,850 and the Unit 7 Fuel Additive project has been increased to \$483,240, all to reflect the new forecast. The Unit 17 and Unit 18 TR Set projects had a unique TR Set design which was identified as a risk at project initiation, however this risk was never realized and as a result the budget forecast has decreased by \$1,000,000 for each project. The ACI projects were able to take advantage of the execution occurring in succession and utilized the same installation crews, the same project teams and the same support groups and as a result the budget forecast has decreased by \$6,000,000 in the aggregate for the ACI group of projects. The Unit 7 Fuel Additive Project forecast increased due to foundation constructability issues by \$85,000 to \$483,240, which is still below the initial amount of \$531,240 approved in the 44311 Order.

Based on our review of the evidence, we find that NIPSCO's proposed changes in estimated costs are reasonable, and we approve.

Mr. Sangster testified the total cost estimate approved in the Sixteenth Progress Report was \$858,941,535 for the Compliance Plan Capital projects and \$2,225,000 for the MATS O&M Projects. Mr. Sangster testified the proposed revised total cost estimate for all Compliance Plan projects is \$850,594,882, which is a decrease of \$8,346,643. The total cost estimate of the MATS O&M Projects did not change.

As part of its Seventeenth Progress Report, NIPSCO is requesting approval of its updated Environmental Compliance Projects cost estimate of \$850,594,882 and approval to recover these costs through the ECRM and EERM.

Based on the evidence presented and our discussion above, we find that the Seventeenth Progress Report is reasonable. Therefore, we approve the modifications to the schedule, the additions and subtractions, and the cost estimates in the Progress Report, and we authorize NIPSCO to recover these costs through its ECRM and EERM.

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

1. NIPSCO is authorized to reflect the additional values of Environmental Compliance Projects identified above in its rates and charges for electric service in accordance with NIPSCO's ECRM beginning with the May 2016 billing cycle.

2. NIPSCO is authorized to reflect the rate adjustments reflecting the recovery of operation, maintenance, and depreciation expenses identified above in its rates and charges for electric service in accordance with NIPSCO's EERM, beginning with the May 2016 billing cycle.

3. Prior to implementing the authorized rates, NIPSCO shall file the applicable rate schedules under this Cause for approval by the Commission's Energy Division.

4. NIPSCO is authorized to defer 20% of the federally mandated costs incurred in connection with the federally mandated MATS O&M Projects and recover those deferred costs in its next general rate case, and NIPSCO is authorized to record ongoing carrying charges based on the current overall weighted average cost of capital on all deferred federally mandated costs until the deferred federally mandated costs are included for recovery in NIPSCO's base rates in its next general rate case.

5. Pursuant to Ind. Code § 8-1-8.7-7 and as approved in Cause Nos. 44311, NIPSCO's modified Compliance Plan, as set forth in the Seventeenth Progress Report, is approved.

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

STEPHAN, HUSTON, AND ZIEGNER CONCUR; WEBER NOT PARTICIPATING:

APPROVED:

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

Mary M. Becerra

**Mary M. Becerra
Secretary of the Commission**

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY FOR APPROVAL OF: (1) AN ADJUSTMENT TO ITS ELECTRIC SERVICE RATES THROUGH ITS ENVIRONMENTAL COST RECOVERY MECHANISM FACTORS PURSUANT TO IND. CODE §§ 8-1-2-6.6, 8-1-2-6.8, CH. 8-1-8.4, CH. 8-1-8.7, CH. 8-1-8.8 AND 170 IAC 4-6-1, *ET SEQ.* AND THE COMMISSION'S ORDERS IN CAUSE NOS. 42150, 43188, 44012, 44311 AND 44688; AND (2) MODIFICATIONS TO THE ENVIRONMENTAL COMPLIANCE PROJECTS SET FORTH IN ITS EIGHTEENTH PROGRESS REPORT PURSUANT TO THE ONGOING REVIEW PROCESS UNDER IND. CODE § 8-1-8.7-7 AND APPROVED IN CAUSE NOS. 42150, 43188, 44012 AND 44311.	)	**CAUSE NO. 42150 ECR 28** **APPROVED:** OCT 26 2016

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ORDER OF THE COMMISSION

Presiding Officers:
David E. Ziegner, Commissioner
Loraine L. Seyfried, Chief Administrative Law Judge

On August 12, 2016, Northern Indiana Public Service Company ("NIPSCO") filed its Verified Petition in this Cause. On that same day and in support of its requested relief, NIPSCO filed the direct testimony and attachments of the following witnesses:[1]

- Jennifer L. Shikany, Director of Regulatory Accounting for NIPSCO;
- Kurt W. Sangster, Vice President, Projects and Construction Electric at NIPSCO;
- David T. Walter, Director, Operations & Maintenance for NIPSCO; and
- Kelly R. Carmichael, Vice President, Environmental for NiSource Corporate Services Company

On August 22, 2016, the NIPSCO Industrial Group ("Industrial Group") filed its Petition to Intervene, which the Presiding Officers granted in a Docket Entry dated September 1, 2016.

On September 26, 2016, the Indiana Office of Utility Consumer Counselor ("OUCC") filed the testimony of Wes. R. Blakley, Senior Utility Analyst.

[1] NIPSCO filed revisions to its case in chief on September 15, 2016, and notification of a substitution of witness with revised testimony on September 19, 2016.

The Commission held an evidentiary hearing at 1:30 p.m. on October 3, 2016, in Room 224, 101 West Washington Street, Indianapolis, Indiana. NIPSCO, the OUCC, and the Industrial Group appeared at the hearing. No member of the public appeared or participated.

Having considered the evidence presented and the applicable law, the Commission finds:

1. **Notice and Jurisdiction.** Notice of the hearing in this case was given and published by the Commission 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 §§ 8-1-2-6.6 and 8-1-2-6.8 and Ind. Code chs. 8-1-8.7 and 8-1-8.8, the Commission has jurisdiction over a public utility's cost recovery related to the use of clean coal technology. Therefore, the Commission has jurisdiction over NIPSCO and the subject matter of this case.

2. **NIPSCO's Characteristics.** Petitioner is a public utility organized and existing under Indiana law, with its principal office at 801 E. 86th Street, Merrillville, Indiana 46410. NIPSCO owns and operates property and equipment used for the production, transmission, delivery and furnishing of electric utility service to the public in northern Indiana.

3. **Background and Relief Requested.** On July 18, 2016, the Commission issued its Order in Cause No. 44688 ("44688 Order"), NIPSCO's most recent rate case, wherein the Commission approved NIPSCO's proposal to roll into basic rates certain costs of environmental compliance projects placed into service as of June 30, 2015 that had been receiving cost recovery under NIPSCO's Rider 672 – Environmental Cost Recovery Mechanism ("ECRM") and Rider 673 – Environmental Expense Recovery Mechanism adjustment mechanisms. The Commission also approved NIPSCO's proposal to consolidate Rider 672 with Rider 673. Consequently, the ECRM adjustment mechanism continues to allow for the periodic recovery of costs relating to NIPSCO's NOx Compliance Plan, Multi-Pollutant Compliance Plan, and Mercury and Air Toxics Standards ("MATS") Compliance Plan projects that were not in service as of June 30, 2015, and therefore not reflected in the rate case proceeding.

Accordingly, in this proceeding, NIPSCO seeks approval of revised ECRM factors to be effective for bills issued during the billing cycles of November 2016 through April 2017. NIPSCO also requests approval of proposed modifications to its environmental compliance projects and cost estimates detailed in its Eighteenth Progress Report.

4. **Commission Discussion and Findings.**

A. **Relevant Period.** Ms. Shikany testified that NIPSCO requests approval of revised ECRM factors to be applicable to the bills rendered during the billing cycles of November 2016 through April 2017. The ECRM factors include actual capital costs and operating, maintenance, and depreciation expenses in connection with the operation of its environmental compliance projects that were in service during the six months ended June 30, 2016 and the recoverable portion (80%) of the MATS Compliance Plan expenses incurred through June 30, 2016. The ECRM factors also include a reconciliation of projected period recoveries of capital cost revenue with actual revenue during the period November 2015 through April 2016 and operating, maintenance, and depreciation revenue with actual revenue during the period May 2015 through April 2016.

B. **Actual Capital Costs.** Ms. Shikany testified that the total cost of environmental compliance projects under construction, net of accumulated depreciation, upon which NIPSCO is authorized to earn a return is $266,982,437. She stated the construction costs include an allowance for funds used during construction ("AFUDC"), computed in accordance with the Federal Energy Regulatory Commission Uniform System of Accounts. Ms. Shikany testified that if the Commission approves the proposed ratemaking treatment for the values shown on Petitioner's Exhibit 1, Attachment 1A, Schedule 1B, NIPSCO will cease accruing AFUDC on those costs since NIPSCO will then be allowed a return on that value and those amounts.

Mr. Sangster testified that Petitioner's Exhibit 1, Attachment 1A, Schedules 1, 1A, and 1B describe the environmental compliance projects under construction which have been approved by the Commission and on which NIPSCO proposes to earn a return. Schedules 1, 1A and 1B set out a brief description of the projects, approved cost estimates, construction start dates, estimated and actual in-service dates, and prior and current project costs. The costs for the environmental compliance projects have been compiled through June 30, 2016. Mr. Sangster testified all of the projects for which NIPSCO is seeking ratemaking treatment in this Cause have been under construction for at least six months.

Based on the evidence presented, we find that NIPSCO's request to begin earning a return on $266,982,437, the value of its environmental compliance projects as of June 30, 2016, net of accumulated depreciation, is reasonable and we approve the request.

C. **Actual Operation and Maintenance ("O&M") Expenses.** Mr. Walter testified that as shown on Petitioner's Exhibit 1, Attachment 2A, Schedule 1, Page 2 (lines 1 through 23), for the period January through June, 2016, NIPSCO incurred $8,588,741 [Line 24, Column B] of actual O&M expenses associated with NIPSCO's ownership and operation of the environmental compliance projects (capital projects) and recoverable federally mandated MATS Compliance Plan O&M projects, of which $371,587 [Line 24, Column C] was fixed and $8,217,153 [Line 24, Column D] was variable.

1. **Environmental Compliance Projects.** Mr. Walter identified the breakdown of actual O&M expenses incurred during the period January through June, 2016 as shown on Petitioner's Exhibit 1, Attachment 2A, Schedule 1, Page 2. Mr. Walter testified the significant increase in O&M expenses during the period January through June, 2016 relates to an increase in expenditures for the Unit 12 flue gas desulfurization ("FGD") technology that came online in December 2015 ($1,629,007), and the Unit 14 FGD, U14/15 Common and Unit 15 FGD forced outages ($5,852,494). He also identified seven new O&M expense categories since NIPSCO's last ECR proceeding.

2. **MATS Compliance Plan O&M Projects.** Mr. Walter testified that in its Order in Cause No. 44311 ("44311 Order"), the Commission approved the following federally mandated O&M projects as part of NIPSCO's MATS Compliance Plan: (1) Precipitator & FGD Mist Eliminator Cleaning for Bailly Units 7 and 8; (2) ESP Flow Modeling for Schahfer Unit 15; and (3) Air Testing for Schahfer Units 14, 15, 17 and 18. In Cause No. 42150 ECR 24, the Commission approved a federally mandated O&M project for Unit 12 ESP Flow Modifications. Mr. Walter described each of the projects and indicated that during the period

January through June 2016, NIPSCO had only incurred costs related to the Precipitator & FGD Mist Eliminator Cleaning for Bailly Units 7 and 8. As reflected on Petitioner's Exhibit 1, Attachment 2A, Schedule 1A, NIPSCO incurred $154,596, of which $48,916 related to Unit 7 and $105,680 related to Unit 8.

Based on the evidence presented, we find that NIPSCO's actual O&M expense associated with NIPSCO's environmental compliance projects (capital projects) and recoverable federally mandated MATS Compliance Plan O&M project expenses for the period ending June 30, 2016, of $8,588,741 are reasonable and we approve recovery of such expenses through the ECRM.

D. Actual Depreciation Expense. Petitioner's Exhibit 1, Attachment 2A, Schedule 1, Page 1, shows that NIPSCO's actual depreciation expense for the six months ending June 30, 2016 was $21,248,790. Ms. Shikany testified that the actual depreciation expense consists of depreciation expenses associated with NIPSCO's ownership and operation of the environmental compliance project facilities that have been placed in service. She stated that the actual depreciation expense was computed based on the depreciation lives and/or rates approved in Cause Nos. 42150, 43188, 44012, and 44311.

Based on the evidence presented, we find that NIPSCO's actual depreciation expense for the six-month period ending June 30, 2016 of $21,248,790 has been properly calculated and is reasonable. Therefore, we approve the actual depreciation expense for recovery through the ECRM.

E. Allocation of Actual Capital Costs and O&M and Depreciation Expenses. Ms. Shikany sponsored Petitioner's Exhibit 1, Attachment 1A, Schedule 5 showing the demand allocation percentages and Attachment 2A, Schedule 1, Page 3 showing the demand and energy allocation percentages attributable to each of NIPSCO's rate schedules as approved in the 44688 Order. The demand allocators approved for purposes of the ECRM adjustment were set forth in Joint Exhibit B to the Stipulation and Settlement Agreement approved in the 44688 Order. Ms. Shikany testified NIPSCO has not adjusted its demand allocators in this filing to reflect any significant migration of customers.

Based on the evidence presented, we find that NIPSCO's proposed ECRM factors have been properly allocated.

F. Reconciliation of Actual Capital Costs and O&M and Depreciation Expenses. Ms. Shikany sponsored Petitioner's Exhibit 1, Attachment 1A, Schedule 6 showing NIPSCO's reconciliation of projected period recoveries of ECRM revenue with actual revenue during the period November 2015 through April 2016. NIPSCO's total computed under- or over-recoveries of ECRM revenue for this period are reflected in Column D, which for this Cause shows an under-recovery of $1,174,966.

Ms. Shikany also sponsored Petitioner's Exhibit 1, Attachment 2A, Schedule 2 showing NIPSCO's reconciliation of projected expense revenue with actual expense revenue during the period May 1, 2015 through April 30, 2016. NIPSCO's total computed under- or over-recoveries of expense revenue for this period are reflected in Column D, which in this Cause shows an under-recovery of $1,410,444.

Based on the evidence presented, we find that NIPSCO properly included a reconciliation of projected period under-recoveries to be collected through the ECRM.

G. Deferred Federally Mandated Costs. Ms. Shikany testified that Petitioner's Exhibit 1, Attachment 2A, Schedule 1A shows the detail of all expenses incurred in connection with NIPSCO's federally mandated MATS Compliance Plan O&M projects. She testified that in accordance with the 44311 Order and Ind. Code § 8-1-8.4-7(c), NIPSCO will defer, as a regulatory asset on the balance sheet, 20% of all costs associated with the approved projects, including post in-service carrying charges on the deferred O&M expenses, for recovery in NIPSCO's next general rate case. Petitioner's Exhibit 1, Attachment 2A, Schedule 3 reflects the deferred federally mandated costs as well as the ongoing carrying charges on those deferred costs.

Based on the evidence presented and pursuant to the 44311 Order and Ind. Code § 8-1-8.4-7(c)(2), we authorize NIPSCO to defer 20% of the federally mandated costs incurred in connection with the federally mandated MATS Compliance Plan O&M projects and recover those deferred costs in its next general rate case. In addition, we authorize NIPSCO to record ongoing carrying charges based on the current overall weighted average cost of capital on all deferred federally mandated costs until the deferred federally mandated costs are included for recovery in NIPSCO's base rates in its next general rate case as allowed by Ind. Code § 8-1-8.4-7(c)(2).

H. Semi-Annual Revenue Requirement. Ms. Shikany testified that Petitioner's Exhibit 1, Attachment 1A, Schedule 4, Page 1 shows NIPSCO's proposed return requirement on its environmental compliance projects at June 30, 2016 is $13,327,482, which is the product of the value of NIPSCO's environmental compliance projects multiplied by the debt and equity components of its weighted cost of capital, adjusted for taxes and multiplied by 0.50. Petitioner's Exhibit 1, Attachment 1A, Schedule 7 shows that NIPSCO's six-month revenue requirement related to the Environmental Compliance Projects at June 30, 2016 is $14,502,448 after including the prior period variance.

Ms. Shikany sponsored the calculation of NIPSCO's 6.66% weighted cost of capital, per books, at June 30, 2016, which is the date of valuation of the environmental compliance projects in accordance with 170 IAC 4-6-14. She testified the cost rates for long-term debt reflect the 12 months ended June 30, 2016. In addition, the cost rates for common equity capital of 9.975% and customer deposits of 4.58% are those approved by the Commission in its 44688 Order. She testified that deferred taxes and the reserve for post-retirement benefits and the capital structure offset relating to the prepaid pension asset are treated as zero-cost capital. The cost of post-1970 investment tax credits reflects the weighted costs of long-term debt and common equity capital. Ms. Shikany testified that NIPSCO's weighted average cost of capital of 6.66% reflects a 17 basis point increase from the 6.49% approved in Cause No. 42150 ECR 27.

Based on the evidence presented, we find that NIPSCO's proposed adjusted semi-annual revenue requirement of $14,502,448 is reasonable, and we approve the revenue requirement.

I. New ECRM Factors. Ms. Shikany sponsored Petitioner's Exhibit 1, Attachment 4, showing the proposed ECRM factors and explained how the ECRM factors were developed. She testified the estimated average monthly bill impact for a typical residential customer using 698 kWh per month is $6.51, which is an increase of $1.95 from what a customer will pay using the approved October 2016 ECRM factors. Ms. Shikany testified the estimated average monthly bill impact for a typical residential customer using 1,000 kWh per month is $9.33, which is an increase of $2.79 from what a customer will pay using the approved October 2016 ECRM factors.

Mr. Blakley testified that nothing came to his attention that would indicate that NIPSCO's calculation of the estimated ECRM factors for the relevant period is unreasonable.

Based on the evidence presented, we approve the proposed ECRM factors set forth in Petitioner's Exhibit 1, Attachment 4 to be applicable for bills rendered during the billing cycles of November 2016 through April 2017.

5. <u>Commission Findings and Conclusions Regarding Progress Report</u>. In its November 26, 2002 Order in Cause No. 42150, the Commission approved NIPSCO's proposal that the Commission maintain an ongoing review of its environmental compliance project construction and expenditures and submit to the Commission annually a report of any revisions of its plan and cost estimates for such construction ("Progress Report"). In its August 25, 2010 Order in Cause No. 43526, the Commission ordered NIPSCO to file its Progress Reports on the status of environmental compliance projects tracked in the ECRM as part of its ECRM filings rather than in a separate proceeding. The Commission's December 28, 2011 Phase I Order in Cause No. 44012 approved NIPSCO's request to file semi-annual progress reports (as opposed to annual progress reports) as part of the ongoing review process under Ind. Code § 8-1-8.7-7. In addition, the 44311 Order authorized NIPSCO to seek timely recovery of the MATS Compliance Plan projects as part of NIPSCO's semi-annual progress reports filed in ECR proceedings and to provide updates to the MATS Compliance Plan capital projects through its semi-annual ECRM proceedings.

Pursuant to the ongoing review process under Ind. Code § 8-1-8.7-7 and as approved in the 44311 Order, NIPSCO requests approval of its Eighteenth Progress Report on the status of environmental compliance projects tracked in the ECRM and approval to recover the revised costs of its environmental compliance projects through the ECRM. Mr. Sangster testified that since its Seventeenth Progress Report approved by the Commission in Cause No. 42150 ECR 27, NIPSCO has identified aspects of its Compliance Plan that require further modification. Mr. Sangster sponsored Petitioner's Exhibit 1, Attachment PR setting forth NIPSCO's Compliance Plan containing the NOx Compliance Plan, Multi-Pollutant Compliance Plan and MATS Compliance Plan highlighted to show proposed modifications. He explained the modifications can be broken down into several categories: scheduling changes, scope additions, changes in estimated costs, and changes due to the implementation of new base rates.

As to the scheduling changes, Mr. Sangster testified the construction start and in-service dates for the Unit 7 SCR Catalyst 3rd Layer was revised to reflect the actual dates. The in-service date for the Unit 12 SCR Catalyst 1st Layer and the construction start and in-service dates for the Unit 14 SCR 1st Layer were revised to reflect the current schedule. The in-service dates for the Unit 12 ACI System and the Unit 12 Fuel Additive projects were revised to reflect the actual dates.

As to the scope additions, Mr. Sangster testified NIPSCO has added three catalyst layer projects to its Compliance Plan in the Eighteenth Progress Report. These projects include: Unit 12 SCR Catalyst 2nd Layer (replacement); Unit 7 SCR Catalyst 4th Layer (replacement); and Unit 8 SCR Catalyst 1st Layer (replacement). He stated that all three of the requested catalyst layer projects are replacement layers and NIPSCO requests ratemaking treatment consistent with the Commission's Order in Cause No. 42150 ECR 21.

Mr. Sangster testified the total cost estimate approved in the Seventeenth Progress Report was $850,594,882 for the Compliance Plan capital projects and $2,225,000 for the MATS Compliance Plan O&M projects. Mr. Sangster testified the proposed revised total cost estimate for the Compliance Plan capital projects is $280,539,797. He explained a decrease of $574,895,085 relates to the previously approved qualifying pollution control property, clean coal technology, clean energy projects, and federally mandated compliance projects, placed into service as of June 30, 2015, now being included in its basic rates and charges. An increase of $4,840,000 relates to the three new proposed SCR Catalyst Layer projects. In addition, Mr. Sangster testified the proposed revised estimate for the MATS Compliance Plan O&M projects is $650,000. He explained a decrease of $1,575,000 relates to the previously approved projects placed in service as of June 30, 2015, now being included in basic rates and charges.

Based on the evidence presented and the foregoing discussion, we find that the Eighteenth Progress Report is reasonable. Therefore, we approve the proposed modifications to the Compliance Plan and authorize NIPSCO to recover these costs through its ECRM.

Finally, Mr. Sangster summarized how NIPSCO has complied with the stakeholder reporting and meeting requirements established in the 44311 Order. He testified that consistent with the 44311 Order, NIPSCO has been providing the OUCC and Industrial Group on a quarterly basis since February of 2014, a quarterly status report for the Transformer Rectifier Set Projects, the Activated Carbon Injection Projects and the Fuel Additive Projects. These quarterly status reports contained information about project schedules, project budgets, and project risks. Mr. Sangster stated that since construction is complete and the projects within the MATS Compliance Plan have gone into service, NIPSCO will no longer produce the quarterly status reports and believes there are no further reporting activities associated with the 44311 Order.

Based on our review of the evidence, we agree and find that there are no further reporting activities associated with the 44311 Order.

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

1. NIPSCO is authorized to implement the rate adjustments reflecting the recovery of capital costs and operation, maintenance, and depreciation expenses identified above in its rates and charges for electric service in accordance with NIPSCO's ECRM beginning with the November 2016 billing cycle.

2. Prior to implementing the ECRM factors approved herein, NIPSCO shall file the applicable rate schedules under this Cause for approval by the Commission's Energy Division.

3. NIPSCO is authorized to defer 20% of the federally mandated costs incurred in connection with the federally mandated MATS Compliance Plan O&M projects and recover those deferred costs in its next general rate case, and NIPSCO is authorized to record ongoing carrying charges based on the current overall weighted average cost of capital on all deferred federally mandated costs until the deferred federally mandated costs are included for recovery in NIPSCO's base rates in its next general rate case.

4. Pursuant to Ind. Code § 8-1-8.7-7 and as approved in Cause No. 44311, NIPSCO's modified Compliance Plan, as set forth in the Eighteenth Progress Report, is approved.

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

<u>STEPHAN, FREEMAN, HUSTON, WEBER, AND ZIEGNER CONCUR</u>:

APPROVED: OCT 26 2016

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

Mary M. Becerra

Mary M. Becerra
Secretary of the Commission

ORIGINAL

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY FOR APPROVAL OF: (1) AN ADJUSTMENT TO ITS ELECTRIC SERVICE RATES THROUGH ITS ENVIRONMENTAL COST RECOVERY MECHANISM FACTORS PURSUANT TO IND. CODE §§ 8-1-2-6.6, 8-1-2-6.8, CH. 8-1-8.4, CH. 8-1-8.7, CH. 8-1-8.8 AND 170 IAC 4-6-1, *ET SEQ.* AND THE COMMISSION'S ORDERS IN CAUSE NOS. 42150, 43188, 44012, 44311 AND 44688; AND (2) MODIFICATIONS TO THE ENVIRONMENTAL COMPLIANCE PROJECTS SET FORTH IN ITS NINETEENTH PROGRESS REPORT PURSUANT TO THE ONGOING REVIEW PROCESS UNDER IND. CODE § 8-1-8.7-7 AND APPROVED IN CAUSE NOS. 42150, 43188, 44012 AND 44311.

CAUSE NO. 42150 ECR 29

APPROVED: APR 26 2017

ORDER OF THE COMMISSION

Presiding Officers:
David E. Ziegner, Commissioner
Marya E. Jones, Administrative Law Judge

On January 31, 2017, Northern Indiana Public Service Company ("NIPSCO") filed its Verified Petition in this Cause. On that same day and in support of its requested relief, NIPSCO filed the direct testimony and attachments of the following witnesses:

- Jennifer L. Shikany – Director of Regulatory Accounting for NIPSCO;
- Greg Baacke – Manager of Generation Major Projects for NIPSCO;
- David T. Walter – Director of Operations & Maintenance for NIPSCO; and
- Kelly R. Carmichael – Vice President of Environmental for NiSource Corporate Services Company.

On February 3, 2017, the NIPSCO Industrial Group ("Industrial Group") filed its Petition to Intervene, which the Presiding Officers granted at the evidentiary hearing.

On March 21, 2017, the Indiana Office of Utility Consumer Counselor ("OUCC") prefiled the testimony of Wes R. Blakley, Senior Utility Analyst.

The Commission held an evidentiary hearing in this Cause at 9:30 a.m. on March 28, 2017, in Room 224, 101 West Washington Street, Indianapolis, Indiana. NIPSCO, the OUCC, and the Industrial Group appeared at the hearing. No member of the public appeared or participated.

Having considered the evidence presented and the applicable law, the Commission finds:

1. **Notice and Jurisdiction.** Notice of the hearing in this case was given and published by the Commission 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 §§ 8-1-2-6.6 and 8-1-2-6.8 and Ind. Code chs. 8-1-8.7 and 8-1-8.8, the Commission has jurisdiction over a public utility's cost recovery related to the use of clean coal technology and other pollution control equipment. Therefore, the Commission has jurisdiction over NIPSCO and the subject matter of this case.

2. **NIPSCO's Characteristics.** Petitioner is a public utility organized and existing under Indiana law, with its principal office at 801 E. 86th Street, Merrillville, Indiana 46410. NIPSCO owns and operates property and equipment used for the production, transmission, delivery, and furnishing of electric utility service to the public in northern Indiana.

3. **Relief Requested.** In this proceeding, NIPSCO requests approval of revised Environmental Cost Recovery Mechanism ("ECRM") factors to be effective for bills issued during the billing cycles of May 2017 through October 2017. NIPSCO also requests approval of proposed modifications to its environmental compliance projects and cost estimates detailed in its Nineteenth Progress Report.

4. **Commission Discussion and Findings.**

A. **Relevant Period.** Ms. Shikany testified that NIPSCO requests approval of revised ECRM factors to be applicable to the bills rendered during the billing cycles of May 2017 through October 2017. The ECRM factors include capital costs, operating and maintenance, and depreciation expenses in connection with the operation of its environmental compliance projects that were in service during the six months ended December 31, 2016, and the recoverable portion (80%) of the MATS Compliance Plan expenses incurred through December 31, 2016. The ECRM factors also include a reconciliation of projected period recoveries of capital cost revenue with actual revenue during the period May 2016 through October 2016 and operating and maintenance, and depreciation revenue with actual revenue during the period May 2016 through October 2016.

B. **Actual Capital Costs.** Ms. Shikany testified that the total cost of environmental compliance projects under construction, net of accumulated depreciation, upon which NIPSCO is authorized to earn a return is $260,535,340. She stated the construction costs include an allowance for funds used during construction ("AFUDC"), computed in accordance with the Federal Energy Regulatory Commission Uniform System of Accounts. Ms. Shikany testified that if the Commission approves the proposed ratemaking treatment for the values shown on Petitioner's Exhibit 1, Attachment 1A, Schedule 1B, NIPSCO will cease accruing AFUDC on those costs since NIPSCO will then be allowed a return on that value and those amounts.

Mr. Baacke testified that Petitioner's Exhibit 1, Attachment 1A, Schedules 1, 1A, and 1B describe the environmental compliance projects under construction which have been approved by the Commission and on which NIPSCO proposes to earn a return. Schedules 1, 1A, and 1B set out a brief description of the projects, approved cost estimates, construction start dates, estimated and actual in-service dates, and prior and current projects costs. The costs for the environmental compliance projects have been compiled through December 31, 2016. Mr. Baacke testified all of the projects for which NIPSCO is seeking ratemaking treatment in this filing have been under construction for at least six months.

Ms. Shikany testified that Petitioner's Exhibit 1, Attachment 1A, Schedule 4, page 1 shows NIPSCO's proposed capital revenue requirement on its environmental compliance projects at December 31, 2016 is $12,713,881, which is the product of NIPSCO's environmental compliance projects value at December 31, 2016, multiplied by the debt and equity components of its weighted cost of capital, computing the 12-month and six-month revenue requirement related to the environmental compliance projects. Ms. Shikany sponsored the calculation of NIPSCO's 6.53% weighted cost of capital at December 31, 2016, which is the date of valuation of the environmental compliance projects in accordance with 170 IAC 4-6-14. She testified the cost rates for long-term debt reflect the 12 months ended December 31, 2016, and the cost rates for common equity capital of 9.975% and customer deposits of 4.58% are those approved by the Commission in its July 18, 2016 Order in Cause No. 44688, ("44688 Order"). She testified that deferred taxes, the reserve for post-retirement benefits, and the capital structure offset relating to the prepaid pension asset are treated as zero-cost capital. She said the cost of post-1970 investment tax credits reflects the weighted costs of long-term debt and common equity capital. Ms. Shikany testified that NIPSCO's weighted average cost of capital of 6.53% reflects a decrease of 13 basis points from the 6.66% approved in Cause No. 42150-ECR-28.

Based on the evidence presented, we find that NIPSCO's request to begin earning a return on $260,535,340, the value of its environmental compliance projects as of December 31, 2016, net of accumulated depreciation, is reasonable, and we approve the request. We also find, based on the evidence presented, that NIPSCO's proposed adjusted semi-annual revenue requirement of $12,713,881 is reasonable, and we approve the revenue requirement.

C. <u>Actual Operation and Maintenance ("O&M") Expenses</u>. Mr. Walter testified that, as shown on Petitioner's Exhibit 1, Attachment 2A, Schedule 1, Page 2 (lines 1 through 27), for the period July through December 2016, NIPSCO incurred $7,533,033 [Line 27, Column B] of actual O&M expenses associated with NIPSCO's ownership and operation of the environmental compliance projects (capital projects) and recoverable federally mandated MATS Compliance Plan O&M projects, of which $633,715 [Line 27, Column C] was fixed and $6,899,318 [Line 27, Column D] was variable.

1. <u>Environmental Compliance Projects</u>. Mr. Walter testified that while there were increases and decreases during the period July through December 2016, the O&M expenses resulted in a net decrease of $1,055,708. He also identified three new O&M expense categories since NIPSCO's last ECR proceeding.

2. **<u>MATS Compliance Plan O&M Projects</u>.** Mr. Walter testified that in its November 20, 2007 Order in Cause No. 44311 ("44311 Order"), the Commission approved the following federally mandated O&M projects as part of NIPSCO's MATS Compliance Plan: (1) Precipitator & FGD Mist Eliminator Cleaning for Bailly Units 7 and 8; (2) ESP Flow Modeling for Schahfer Unit 15; and (3) Air Testing for Schahfer Units 14, 15, 17 and 18. In Cause No. 42150-ECR-24, the Commission approved a federally mandated O&M project for Unit 15 ESP Flow Modifications. Mr. Walter described each of the projects and indicated that during the period July through December 2016, NIPSCO had only incurred costs related to the Precipitator & FGD Mist Eliminator Cleaning for Bailly Units 7 and 8. As reflected in Petitioner's Exhibit 1, Attachment 2A, Schedule 1A, NIPSCO incurred $237,329, of which $119,713 related to Unit 7 and $117,616 related to Unit 8.

Based on the evidence presented, we find that NIPSCO's actual O&M expense associated with NIPSCO's environmental compliance projects (capital projects) and recoverable federally mandated MATS Compliance Plan O&M project expenses for the period ending December 31, 2016, of $7,533,033 are reasonable and we approve recovery of such expenses through the ECRM.

D. **<u>Actual depreciation expense</u>.** Petitioner's Exhibit 1, Attachment 2A, Schedule 1, Page 1, shows that NIPSCO's actual depreciation expense for the six months ending December 31, 2016 was $14,105,246. Ms. Shikany testified that the actual depreciation expense consists of depreciation expenses associated with NIPSCO's ownership and operation of the environmental compliance projects facilities that have been placed in service. She stated that the actual depreciation expense was computed based on the depreciation lives and/or rates approved in Cause Nos. 44688, 42150, 43188, 44012 and 44311.

Based on the evidence presented, we find that NIPSCO's actual depreciation expense for the six-month period ending December 31, 2016 of $14,105,246 has been properly calculated and is reasonable. Therefore, we approve the actual depreciation expense for recovery through the ECRM.

E. **<u>Allocation of Actual Capital Costs and O&M and Depreciation Expenses</u>.** Ms. Shikany sponsored Petitioner's Exhibit 1, Attachment 1A, Schedule 5 showing the demand allocation percentages and Petitioner's Exhibit 1, Attachment 2A, Schedule 1, Page 3 showing the demand and energy allocation percentages attributable to each of NIPSCO's rate schedules as approved in the 44688 Order. The demand allocators approved for purposes of the ECRM adjustment were set forth in Joint Exhibit B to the Stipulation and Settlement Agreement approved in the 44688 Order. Ms. Shikany testified NIPSCO has adjusted its demand and energy allocation percentages in this filing to reflect the migration of customers.

Based on the evidence presented, we find that NIPSCO's proposed ECRM allocation factors are reasonable, the ECR costs have been properly allocated, and we approve such allocations.

F. **<u>Reconciliation of Actual Capital Costs and O&M and Depreciation Expenses</u>.** Ms. Shikany sponsored Petitioner's Exhibit 1, Attachment 1A, Schedule 6 showing

NIPSCO's reconciliation of projected period recoveries of ECRM revenue with actual revenue during the period May 2016 through October 2016. NIPSCO's total computed under- or over-recoveries of ECRM revenue for this period are reflected in Column D, which in this filing shows an over-recovery of $356,847.

Ms. Shikany also sponsored Petitioner's Exhibit 1, Attachment 2A, Schedule 2 showing NIPSCO's reconciliation of projected expense revenue with actual expense revenue during the period May 2016 through October 2016. NIPSCO's total computed under- or over-recoveries of expense revenue for this period are reflected in Column D, which in this filing shows an over-recovery of $671,595.

Based on the evidence presented, we find that NIPSCO properly included a reconciliation of May 2016 through October 2016 over-recoveries to be reflected in these ECRM-29 factors.

G. <u>Deferred Federally Mandated Costs</u>. Ms. Shikany testified that Petitioner's Exhibit 1, Attachment 2A, Schedule 1A shows the detail of all expenses incurred in connection with NIPSCO's federally mandated MATS Compliance Plan O&M projects. She testified that in accordance with the 44311 Order and Ind. Code § 8-1-8.4-7(c), NIPSCO will defer, as a regulatory asset on the balance sheet, 20% of all costs associated with approved projects, including post in-service carrying charges on the deferred O&M expenses, for recovery in NIPSCO's next general rate case. Petitioner's Exhibit 1, Attachment 2A, Schedule 3 reflects the deferred federally mandated costs as well as the ongoing carrying charges on those deferred costs. The total deferred costs are $146,224.

Based on the evidence presented and pursuant to the 44311 Order and Ind. Code § 8-1-8.4-7(c)(2), we authorize NIPSCO to defer 20% of the federally mandated costs incurred in connection with the Federally Mandated MATS Compliance O&M projects and recover those deferred costs in its next general rate case. In addition, we authorize NIPSCO to record ongoing carrying charges based on the current overall weighted average cost of capital on all deferred federally mandated costs until the deferred federally mandated costs are included for recovery in NIPSCO's base rates in its next general rate case as allowed by Ind. Code § 8-1-8.4-7(c)(2).

H. <u>Semi-Annual Revenue Requirement</u>. Ms. Shikany testified that Petitioner's Exhibit 1, Attachment 3A, Schedule 1 summarizes the capital and expense revenue requirements that were calculated in Attachments 1A and 2A. NIPSCO's proposed total revenue requirement on its environmental compliance projects at December 31, 2016 is $43,707,372. The capital revenue requirement is the sum of the requested capital revenue requirement of $12,713,881 less an amount of $356,847 from the capital cost reconciliation for a total capital revenue requirement of $12,357,034.

The expense revenue requirement is the sum of the requested O&M expenses of $7,533,033, depreciation expense of $14,105,246, and reduced by an amount of $671,595 from the expenses reconciliation for a total expense revenue requirement of $20,966,684. Ms. Shikany explained that the expense revenue requirement is further adjusted for the utilities receipts tax. She explained that Column E represents the 50% amount of the revenue requirement (January through December, 2015) approved in Cause No. 42150-ECR-27 remaining to be collected from the ratepayers at the time NIPSCO made its Compliance Filing – Tariff approved in the 44688 Order. NIPSCO included 50% of that revenue requirement in Cause No. 42150-ECR-28, and has included the remaining 50% of the revenue requirement in this proceeding. Ms. Shikany testified that Column F shows the total revenue requirement which NIPSCO is seeking to recover in this filing. She stated that the forecasted volumes for the billing period are applied to calculate the billing factors shown in Column H.

Based on the evidence presented, we find that NIPSCO's proposed adjusted semi-annual revenue requirement of $43,707,372 is reasonable, and we approve the revenue requirement.

I. <u>New ECRM Factors</u>. Ms. Shikany sponsored Petitioner's Exhibit 1, Attachment 4, showing the proposed ECRM factors and explained how the ECRM factors were developed. She testified the estimated average monthly bill impact for a typical residential customer using 698 kWh per month is $3.58, which is a decrease of $2.93 from what a customer pays using the currently approved ECRM factors. Ms. Shikany testified the estimated average monthly bill impact for a typical residential customer using 1,000 kWh per month is $5.12, which is a decrease of $4.21 from what a customer pays using the currently approved ECRM factors.

Mr. Blakley testified that nothing came to his attention that would indicate that NIPSCO's calculation of estimated ECR adjustment factors for the relevant period is unreasonable.

Based on the evidence presented, we approve the proposed ECRM factors set forth in Petitioner's Exhibit 1, Attachment 4 to be applicable for bills rendered during the billing cycles of May 2017 through October 2017, which begins April 28, 2017, to remain in place until replaced by a different ECRM adjustment that is approved in a subsequent filing.

5. <u>Commission Findings and Conclusions Regarding Progress Report</u>. In its November 26, 2002 Order in Cause No. 42150, the Commission approved NIPSCO's proposal that the Commission maintain an ongoing review of its environmental Compliance Project construction and expenditures and submit to the Commission annually a report of any revisions of its plan and cost estimates for such construction ("Progress Report"). In its August 25, 2010 Order in Cause No. 43526, the Commission ordered NIPSCO to file its Progress Reports on the status of environmental compliance projects tracked in the ECRM as part of its ECRM filings rather than in a separate proceeding. In its December 28, 2011 Phase I Order in Cause No. 44012, the Commission approved NIPSCO's request to file semi-annual progress reports (as opposed to annual progress reports) as part of the ongoing review process under Ind. Code § 8-1-8.7-7. In its 44311 Order, the Commission authorized NIPSCO to seek timely recovery of the MATS Compliance Plan projects as part of NIPSCO's semi-annual progress reports filed in ECR proceedings and to provide updates to the MATS Compliance Plan capital projects through its semi-annual ECRM proceedings.

Pursuant to the ongoing review process under Ind. Code §8-1-8.7-7 and as approved in Cause No. 44311, NIPSCO requests approval of its Nineteenth Progress Report on the status of environmental compliance projects tracked in the ECRM and approval to recover the revised costs of its environmental compliance projects through the ECRM. Mr. Baacke testified that since its Eighteenth Progress Report approved by the Commission in Cause No. 42150-ECR-28, NIPSCO has identified aspects of its Compliance Plan that require further modification. Mr. Baacke sponsored Petitioner's Exhibit 1, Attachment PR setting forth NIPSCO's Compliance Plan containing the NOx Compliance Plan, Multi-Pollutant Compliance Plan, and MATS Compliance Plan highlighted to show proposed modifications. He explained that the modifications can be broken down into several categories: scheduling changes, scope additions and subtractions, changes in estimated costs, and changes due to the implementation of new base rates.

As to the scheduling changes, Mr. Baacke testified the construction start and in service dates for the Unit 14 SCR Catalyst 1st Layer were revised to reflect the actual dates.

As to the scope subtractions, Mr. Baacke testified NIPSCO has removed two catalyst layer projects from its Compliance Plan in the Nineteenth Progress Report (1) Unit 7 SCR Catalyst 4th Layer and (2) Unit 8 SCR Catalyst 1st Layer. He stated that in accordance with NIPSCO's 2016 Integrated Resource Plan, NIPSCO announced its decision to retire Unit 7 and Unit 8 at Bailly Generating Station in 2018. Due to this retirement, these two projects are no longer required. In addition, NIPSCO has added two catalyst layer projects to its Compliance Plan (1) Unit 12 SCR Catalyst 3rd Layer and (2) Unit 14 SCR Catalyst 2nd Layer. Both of the additional catalyst layer projects are replacement layers, and NIPSCO requests ratemaking treatment consistent with the Commission's ECR-21 Order.

Mr. Baacke testified the total cost estimate approved in the Eighteenth Progress Report was $280,539,797 for the Compliance Plan capital projects and $650,000 for the MATS O&M projects. Mr. Baacke testified the revised total cost estimate for the Compliance Plan capital projects is $282,999,797, which is an increase of $2,460,000. The net increase is due to the removal of Unit 7 SCR Catalyst 4th Layer and Unit 8 SCR Catalyst 1st Layer projects that were estimated at $2,540,000 and the addition of the Unit 12 SCR Catalyst 3rd Layer and Unit 14 SCR Catalyst 2nd Layer projects estimated at $5,000,000. Mr. Baacke testified the total cost estimate for the Compliance Plan MATS O&M projects is $650,000, which is unchanged from the Eighteenth Progress Report.

Based on the evidence presented and the foregoing discussion, we find that the Nineteenth Progress Report is reasonable. Therefore, we approve the proposed modifications to the Compliance Plan and authorize NIPSCO to recover these costs through its ECRM, including ratemaking treatment for the catalyst layer projects consistent with our October 16, 2013 Order in Cause No.42150- ECR-21.

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

1. NIPSCO is authorized to implement the rate adjustments reflecting the recovery of capital costs and operation, maintenance and depreciation expenses identified above in its rates and charges for electric service in accordance with NIPSCO's ECRM to become effective for bills rendered by NIPSCO during the billing cycles of May 2017 through October 2017, which begins April 28, 2017, to remain in effect until replaced by a different ECRM adjustment that is approved in a subsequent filing.

2. Prior to implementing the ECRM factors approved herein, NIPSCO shall file the applicable rate schedules under this Cause for approval by the Commission's Energy Division.

3. NIPSCO is authorized to defer 20% of the federally mandated costs incurred in connection with the federally mandated MATS Compliance Plan O&M projects and recover those deferred costs in its next general rate case, and NIPSCO is authorized to record ongoing carrying charges based on the current overall weighted average cost of capital on all deferred federally mandated costs until the deferred federally mandated costs are included for recovery in NIPSCO's base rates in its next general rate case.

4. Pursuant to Ind. Code § 8-1-8.7-7 and as approved in Cause No. 44311, NIPSCO's modified Compliance Plan, as set forth in the Nineteenth Progress Report, is approved.

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

ATTERHOLT, FREEMAN, AND HUSTON CONCUR; WEBER AND ZIEGNER ABSENT:

APPROVED: APR 26 2017

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

Mary M. Becerra

Mary M. Becerra
Secretary of the Commission

ORIGINAL

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY FOR APPROVAL OF: (1) AN ADJUSTMENT TO ITS ELECTRIC SERVICE RATES THROUGH ITS ENVIRONMENTAL COST RECOVERY MECHANISM FACTORS PURSUANT TO IND. CODE §§ 8-1-2-6.6, 8-1-2-6.8, CH. 8-1-8.4, CH. 8-1-8.7, CH. 8-1-8.8 AND 170 IAC 4-6-1, *ET SEQ.* AND THE COMMISSION'S ORDERS IN CAUSE NOS. 42150, 44012, 44311 AND 44688; (2) MODIFICATIONS TO THE ENVIRONMENTAL COMPLIANCE PROJECTS SET FORTH IN ITS TWENTIETH PROGRESS REPORT PURSUANT TO THE ONGOING REVIEW PROCESS UNDER IND. CODE § 8-1-8.7-7 AND APPROVED IN CAUSE NOS. 42150, 44012, AND 44311; AND (3) A MODIFICATION TO APPENDIX D – ENVIRONMENTAL COST RECOVERY MECHANISM FACTOR.	)	CAUSE NO. 42150 ECR 30 APPROVED: OCT 25 2017

ORDER OF THE COMMISSION

Presiding Officers:
David E. Ziegner, Commissioner
Carol Sparks Drake, Administrative Law Judge

On July 28, 2017, Northern Indiana Public Service Company ("NIPSCO" or "Petitioner") filed its Verified Petition in this Cause and the direct testimony and attachments of the following NIPSCO employees:

- Jennifer L. Shikany, Director of Regulatory Accounting;
- Greg Baacke, Manager of Generation Major Projects; and
- David T. Walter, Vice President of Electric Generation.

On August 4, 2017, the NIPSCO Industrial Group ("Industrial Group") filed a Petition to Intervene, which the Presiding Officers granted in a Docket Entry dated August 16, 2017.[1]

On September 20, 2017, the Indiana Office of Utility Consumer Counselor ("OUCC") filed the testimony of Wes. R. Blakley, Senior Utility Analyst.

[1] For purposes of this Cause, the Industrial Group consists of the following companies: ArcelorMittal USA, BP Energy, Praxair, Inc., USG Corporation, and United States Steel Corporation.

The Commission held an evidentiary hearing in this Cause at 10:30 a.m. on October 10, 2017, in Hearing Room 224 of the PNC Center, 101 West Washington Street, Indianapolis, Indiana. NIPSCO, the OUCC, and the Industrial Group appeared at the hearing by counsel, and their respective evidence was admitted without objection. Mr. Blakley's testimony on the OUCC's behalf was limit to the new ECRM factors and related matters discussed below in Finding No. 4.I. No members of the general public appeared.

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

1. **Notice and Jurisdiction.** Notice of the hearing in this Cause was given and published by the Commission as required by law. NIPSCO is a public utility as defined in Ind. Code § 8-1-2-1(a). Under Ind. Code §§ 8-1-2-6.6 and 8-1-2-6.8 and Ind. Code chs. 8-1-8.7 and 8-1-8.8, the Commission has jurisdiction over a public utility's cost recovery related to the use of clean coal technology and other pollution control equipment. The Commission, therefore, has jurisdiction over NIPSCO and the subject matter of this proceeding.

2. **NIPSCO's Characteristics.** Petitioner is a public utility organized under Indiana law with its principal office at 801 East 86th Street, Merrillville, Indiana. NIPSCO owns and operates property and equipment used for the production, transmission, delivery, and furnishing of electric utility service to the public in northern Indiana.

3. **Background and Relief Requested.** In this proceeding, NIPSCO requests approval of revised Environmental Cost Recovery Mechanism ("ECRM") factors to be effective for bills issued during the November 2017 through April 2018 billing cycles, which begin October 31, 2017, and a modification of Appendix D – Environmental Cost Recovery Mechanism Factor. NIPSCO also requests approval of proposed modifications to its environmental compliance projects and cost estimates detailed in its Twentieth Progress Report.

4. **Commission Discussion and Findings.**

A. **Relevant Period.** Ms. Shikany testified that NIPSCO is requesting approval of revised ECRM factors to be applicable to the bills rendered during the November 2017 through April 2018 billing cycles. The ECRM factors include actual capital costs and operating, maintenance, and depreciation expenses in connection with the operation of Petitioner's environmental compliance projects that were in service during the six months ended June 30, 2017, and the recoverable portion (80%) of the MATS Compliance Plan expenses incurred through June 30, 2017. The ECRM factors also include a reconciliation of projected period recoveries of capital cost revenue with actual revenue during the period November 2016 through April 2017 and operating, maintenance, and depreciation revenue with actual revenue during the period November 2016 through April 2017.

B. **Actual Capital Costs.** According to Ms. Shikany, the total cost of environmental compliance projects under construction, net of accumulated depreciation, upon which NIPSCO is authorized to earn a return is $254,500,942. She stated the construction costs include an allowance for funds used during construction ("AFUDC"), computed in accordance with the Federal Energy Regulatory Commission Uniform System of Accounts. Ms. Shikany testified that if the Commission approves the proposed ratemaking treatment for the values shown on Attachment 1, Schedule 1B, to the Verified Petition filed in this Cause ("Attachment 1-A"), NIPSCO will cease accruing AFUDC on those costs because NIPSCO will then be allowed a return on that value and those amounts.

Mr. Baacke testified that Petitioner's Attachment 1-A, Attachment 1, Schedules 1, 1A, and 1B describe Commission-approved environmental compliance projects under construction and on which NIPSCO proposes to earn a return. Schedules 1, 1A, and 1B include a brief description of the projects, approved cost estimates, construction start dates, estimated and actual in-service dates, and prior and current project costs. The costs for the environmental compliance projects have been compiled through June 30, 2017. Mr. Baacke testified all of the projects for which NIPSCO seeks ratemaking treatment in this Cause have been under construction for at least six months.

Based on the evidence presented, the Commission finds NIPSCO's request to begin earning a return on $254,500,942, the value of its environmental compliance projects as of June 30, 2017, net of accumulated depreciation, is reasonable and approves the request.

Ms. Shikany testified that Petitioner's Attachment 1-A, Attachment 1, Schedule 4, page 1 shows NIPSCO's proposed capital revenue requirement on its environmental compliance projects at June 30, 2017, is $12,430,109, which is the product of the value of NIPSCO's environmental compliance projects at June 30, 2017, multiplied by the debt and equity components of NIPSCO's weighted cost of capital grossed up for taxes, computing the 12-month and six-month revenue requirement related to the environmental compliance projects. Ms. Shikany sponsored the calculation of NIPSCO's 6.5% weighted average cost of capital at June 30, 2017, which utilizes the methodology the Commission approved in Cause No. 44688.

Based on the evidence presented, the Commission finds that NIPSCO's proposed adjusted semi-annual capital revenue requirement of $12,430,109 is reasonable and approves the capital revenue requirement.

C. <u>Actual Operation and Maintenance ("O&M") Expenses</u>. Mr. Walter testified that as shown on Petitioner's Attachment 1-A, Attachment 2, Schedule 1, page 2 (lines 1 through 16), for the period January through June 2017, NIPSCO incurred $2,726,342 of actual operation and maintenance ("O&M") expenses associated with NIPSCO's ownership and operation of the environmental compliance projects (capital projects) and recoverable federally mandated MATS Compliance Plan O&M projects, of which $872,962 was fixed, and $1,853,379 was variable.

1. <u>Environmental Compliance Projects</u>. Mr. Walter identified the breakdown of actual O&M expenses incurred during the January through June 2017 period as shown on Petitioner's Attachment 1-A, Attachment 2, Schedule 1, page 2. Mr. Walter testified there were no noteworthy O&M expense increases during the period January through June 2017, and no new O&M expense categories were created since the O&M expenses approved in Cause No. 42150 ECR 29.

2. <u>MATS Compliance Plan O&M Projects</u>. Mr. Walter testified that in the Order in Cause No. 44311 ("44311 Order"), the Commission approved the following federally mandated O&M projects as part of NIPSCO's MATS Compliance Plan: (1) Precipitator and FGD Mist Eliminator Cleaning for Bailly Units 7 and 8; (2) ESP Flow Modeling for Schahfer Unit 15; and (3) Air Testing for Schahfer Units 14, 15, 17, and 18. In Cause No. 42150 ECR 24, the Commission approved a federally mandated O&M project for Unit 15 ESP Flow Modifications. Mr. Walter described each of the projects and indicated that during the period January through June 2017, NIPSCO only incurred costs related to the ESP Flow Modifications for Schahfer Unit 15 in the amount of $554,545.

Based on the evidence presented, the Commission finds that NIPSCO's actual O&M expense associated with NIPSCO's environmental compliance projects (capital projects) and recoverable federally mandated MATS Compliance Plan O&M project expenses for the period ending June 30, 2017, of $2,726,342 are reasonable and approves recovery of such expenses through the ECRM.

D. Actual Depreciation Expense. Petitioner's Attachment 1-A, Attachment 2, Schedule 1, page 1 shows NIPSCO's actual depreciation expense for the six months ending June 30, 2017, was $6,840,489. Ms. Shikany testified that the actual depreciation expense consists of depreciation expenses associated with NIPSCO's ownership and operation of the environmental compliance project facilities that have been placed in service. She explained that the actual depreciation expense was computed based on the depreciation lives and/or rates approved in Cause Nos. 44688, 42150, 44012, and 44311.

Based on the evidence presented, the Commission finds that NIPSCO's actual depreciation expense for the six months ending June 30, 2017, of $6,840,489 has been properly calculated and is reasonable; therefore, the Commission approves the actual depreciation expense for recovery through the ECRM.

E. Allocation of Actual Capital Costs, O&M, and Depreciation Expenses. Ms. Shikany sponsored Petitioner's Attachment 1-A, Attachment 1, Schedule 5 showing the demand allocation percentages and Attachment 2, Schedule 1, page 3 showing the demand and energy allocation percentages attributable to each of NIPSCO's rate schedules as approved in the 44688 Order. The demand allocators approved for purposes of the ECRM adjustment were set forth in Joint Exhibit B to the Stipulation and Settlement Agreement approved in the 44688 Order. Ms. Shikany testified NIPSCO has adjusted its demand and energy allocation percentages in this filing to reflect the migration of customers.

Based on the evidence presented, the Commission finds that NIPSCO's proposed ECRM allocation factors are reasonable, the ECR costs have been properly allocated, and such allocations are approved.

F. Reconciliation of Actual Capital Costs, O&M, and Depreciation Expenses. Ms. Shikany sponsored Petitioner's Attachment 1-A, Attachment 1, Schedule 6 showing NIPSCO's reconciliation of projected period recoveries of ECRM revenue with actual revenue during the period November 2016 through April 2017. NIPSCO's total computed under- or over-recoveries of ECRM revenue for this period are reflected in Column D, which in this Cause shows an under-recovery of $347,201.

Ms. Shikany also sponsored Petitioner's Attachment 1-A, Attachment 2, Schedule 2 showing NIPSCO's reconciliation of projected expense revenue with actual expense revenue during the period November 2016 through April 2017. NIPSCO's total computed under- or over-recoveries of expense revenue for this period are reflected in Column D, which in this Cause shows an under-recovery of $980,022.

Based on the evidence presented, the Commission finds NIPSCO properly included a reconciliation of November 2016 through April 2017 under-recoveries to be reflected in the ECRM 30 factors.

G. <u>Deferred Federally Mandated Costs</u>. Ms. Shikany testified that Petitioner's Attachment 1-A, Attachment 2, Schedule 1A shows the detail of all expenses incurred in connection with NIPSCO's federally mandated MATS Compliance Plan O&M projects. She testified that in accordance with the 44311 Order and Ind. Code § 8-1-8.4-7(c), NIPSCO will defer, as a regulatory asset on the balance sheet, 20% of all costs associated with the approved projects, including post in-service carrying charges on the deferred O&M expenses, for recovery in NIPSCO's next general rate case. Petitioner's Attachment 1-A, Attachment 2, Schedule 3 reflects the deferred federally mandated costs and the ongoing carrying charges on those deferred costs.

Based on the evidence presented and pursuant to the 44311 Order and Ind. Code § 8-1-8.4-7(c)(2), the Commission authorizes NIPSCO to defer 20% of the federally mandated costs incurred in connection with the federally mandated MATS Compliance Plan O&M projects and recover those deferred costs in Petitioner's next general rate case. The Commission also authorizes NIPSCO to record ongoing carrying charges based on the current overall weighted average cost of capital on all deferred federally mandated costs until the deferred federally mandated costs are included for recovery in NIPSCO's base rates as allowed by Ind. Code § 8-1-8.4-7(c)(2).

H. <u>Semi-Annual Revenue Requirement</u>. Ms. Shikany testified that Petitioner's Attachment 1-A, Attachment 3, Schedule 1 summarizes the capital and expense revenue requirements calculated in Attachments 1 and 2. NIPSCO's proposed total revenue requirement on its environmental compliance projects at June 30, 2017, is $23,483,547. The capital revenue requirement is the sum of the requested capital revenue requirement of $12,430,109 plus an amount of $347,201 from the capital cost reconciliation, for a total capital revenue requirement of $12,777,310 for the billing period of November 2017 through April 2018.

The expense revenue adjustment, as shown on Petitioner's Attachment 1A, Attachment 2, Schedule 1, is the sum of Petitioner's requested O&M expense of $2,726,342 and depreciation expense of $6,840,489, increased by $980,022 from the expenses reconciliation, for a total expense revenue requirement of $10,546,852. Ms. Shikany testified that Column E on Petitioner's Attachment 1-A, Attachment 3, Schedule 1 shows the total revenue requirement which NIPSCO seeks to recover in this Cause, with the forecasted kWh sales for the billing period applied to calculate the billing factors shown in Column G.

Based on the evidence presented, the Commission finds that NIPSCO's proposed adjusted semi-annual revenue requirement of $23,483,547 is reasonable and approves the revenue requirement.

I. New ECRM Factors. Ms. Shikany sponsored Petitioner's Attachment 1-A, Attachment 4, showing the proposed ECRM factors and explained how the ECRM factors were developed. She testified the estimated average monthly bill impact for a typical residential customer using 698 kWh per month is $2.95, which is a decrease of $0.63 from what a customer will pay using the currently approved ECRM factor. Ms. Shikany testified the estimated average monthly bill impact for a typical residential customer using 1,000 kWh per month is $4.22, which is a decrease of $0.90 from what a customer will pay using the currently approved ECRM factor.

Mr. Blakley testified that in response to a data request by the OUCC, NIPSCO identified a minor error in its exhibits. The error resulted in $14,670 of expenses being incorrectly charged to the Unit 12 FGD Project. Mr. Blakley testified the error does not materially change the proposed ECR rate, and the OUCC and NIPSCO have agreed to reconcile this mistake in Petitioner's next ECR filing. Mr. Blakley stated nothing came to his attention that indicated NIPSCO's calculation of the estimated ECRM factors for the relevant period is unreasonable.

Based on the evidence presented, including Mr. Blakley's testimony upon the reasonableness of Petitioner's estimated ECR adjustment factors, the Commission approves the proposed ECRM factors set forth in Petitioner's Attachment 1-A, Attachment 3, Schedule 1 to be applicable for bills rendered during the billing cycles of November 2017 through April 2018, to remain in effect until a different ECRM adjustment is approved in a subsequent filing. The Commission also, consistent with Mr. Blakley's testimony upon the agreement the OUCC and NIPSCO reached to reconcile expenses incorrectly charged in this Cause to the Unit 12 FGD Project, approves reconciling $14,670 of incorrectly allocated expenses in NIPSCO's next ECR proceeding.

J. Modification of Appendix D. Ms. Shikany sponsored Petitioner's Attachment 1-A, Attachment 4 showing NIPSCO's proposed modification of Appendix D. She testified that pursuant to the Commission's January 11, 2017 Order in Cause No. 44828, NIPSCO proposes to modify Appendix D – Environmental Cost Recovery Mechanism Factor to reflect it is also applicable to NIPSCO's Rider 785 – Plug-In Electric Vehicle Off-Peak Charging Rider. The Commission finds the proposed modification of Appendix D is appropriate, and it is approved.

5. Commission Findings and Conclusions Regarding Progress Report. In its November 26, 2002 Order in Cause No. 42150, the Commission approved NIPSCO's proposal that the Commission maintain an ongoing review of NIPSCO's environmental compliance project construction and expenditures and that NIPSCO annually submit to the Commission a report of any revisions of the plan and cost estimates for such construction ("Progress Report"). In its August 25, 2010 Order in Cause No. 43526, the Commission ordered NIPSCO to file the Progress Reports on the status of environmental compliance projects tracked in the ECRM as part of Petitioner's ECRM filings. In its December 28, 2011 Phase I Order in Cause No. 44012, the Commission approved NIPSCO's request to file semi-annual Progress Reports (as opposed to annual) as part of the ongoing review process under Ind. Code § 8-1-8.7-7. In addition, in the 44311 Order, the Commission authorized NIPSCO to seek timely recovery of the MATS Compliance Plan projects as part of NIPSCO's semi-annual Progress Reports filed in ECR proceedings and to provide updates to the MATS Compliance Plan capital projects through the semi-annual ECRM proceedings.

Pursuant to the ongoing review process under Ind. Code § 8-1-8.7-7 and as approved in the 44311 Order, NIPSCO requests approval of its Twentieth Progress Report on the status of environmental compliance projects tracked in the ECRM and approval to recover the revised costs of its environmental compliance projects through the ECRM. Mr. Baacke testified that since NIPSCO's Nineteenth Progress Report approved in Cause No. 42150 ECR 29, NIPSCO has identified aspects of its Compliance Plan that require further modification. Mr. Baacke sponsored Attachment PR to Petitioner's Attachment 1-A. Attachment PR sets forth NIPSCO's Compliance Plan containing the NOx Compliance Plan, Multi-Pollutant Compliance Plan, and MATS Compliance Plan highlighted to show proposed modifications. He testified the modifications consist of only scheduling changes.

As to the scheduling changes, Mr. Baacke testified the in-service dates for the Unit 12 SCR Catalyst 1st Layer and Unit 12 SCR Catalyst 2nd Layer were revised to reflect the estimated in-service dates, and Unit 15 ESP Flow Modification Project was revised to reflect the actual construction start and in-service dates.

Based on the evidence presented, the Commission finds the Twentieth Progress Report is reasonable; therefore, the Commission approves the proposed modifications to the Compliance Plan and authorizes NIPSCO to recover these costs through its ECRM, including ratemaking treatment for the catalyst layer projects consistent with the October 16, 2013 Order in Cause No. 42150 ECR 21.

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

1. NIPSCO is authorized to implement the rate adjustments reflecting the recovery of capital costs, O&M, and depreciation expenses identified above in Petitioner's rates and charges for electric service in accordance with NIPSCO's ECRM beginning with the November 2017 billing cycle, to remain in effect until replaced by a different ECRM adjustment approved in a subsequent filing.

2. As set forth above in Finding No. 4.I., NIPSCO shall reconcile $14,670 of incorrectly allocated expenses in Petitioner's next ECR proceeding.

3. Prior to implementing the approved ECRM factors, NIPSCO shall file the tariff and applicable rate schedules under this Cause for approval by the Commission's Energy Division. Such rate(s) shall be effective for bills NIPSCO renders commencing with the November 2017 billing cycle subject to Division review and agreement with the amounts reflected.

4. NIPSCO is authorized to defer 20% of the federally mandated costs incurred in connection with the federally mandated MATS Compliance Plan O&M projects and recover those deferred costs in its next general rate case, and NIPSCO is authorized to record ongoing carrying charges based on the current overall weighted average cost of capital on all deferred federally mandated costs until the deferred federally mandated costs are included for recovery in NIPSCO's base rates in its next general rate case.

5. Pursuant to Ind. Code § 8-1-8.7-7 and as approved in Cause No. 44311, NIPSCO's modified Compliance Plan, as set forth in the Twentieth Progress Report, is approved.

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

ATTERHOLT, HUSTON, WEBER, AND ZIEGNER CONCUR; FREEMAN ABSENT:

APPROVED: OCT 25 2017

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

Mary M. Becerra

Mary M. Becerra
Secretary of the Commission

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STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

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PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY FOR APPROVAL OF: (1) AN ADJUSTMENT TO ITS ELECTRIC SERVICE RATES THROUGH ITS ENVIRONMENTAL COST RECOVERY MECHANISM FACTORS PURSUANT TO IND. CODE §§ 8-1-2-6.6, 8-1-2-6.8, CH. 8-1-8.4, CH. 8-1-8.7, CH. 8-1-8.8 AND 170 IAC 4-6-1, *ET SEQ.* AND THE COMMISSION'S ORDERS IN CAUSE NOS. 42150, 44012, 44311 AND 44688; AND (2) MODIFICATIONS TO THE ENVIRONMENTAL COMPLIANCE PROJECTS SET FORTH IN ITS TWENTY-FIRST PROGRESS REPORT PURSUANT TO THE ONGOING REVIEW PROCESS UNDER IND. CODE § 8-1-8.7-7 AND APPROVED IN CAUSE NOS. 42150, 44012, AND 44311.	)	**CAUSE NO. 42150 ECR 31** **APPROVED:** APR 25 2018

ORDER OF THE COMMISSION

Presiding Officers:
David E. Ziegner, Commissioner
Carol Sparks Drake, Administrative Law Judge

On January 31, 2018, Northern Indiana Public Service Company ("NIPSCO" or "Petitioner") filed its Verified Petition in this Cause and the direct testimony and attachments of the following witnesses:

- Katherine A. Cherven, Manager of Regulatory for NiSource Corporate Services Company;
- Greg Baacke, Manager of Generation Major Projects at NIPSCO; and
- David T. Walter, Vice President of Electric Generation at NIPSCO.

On January 31, 2018, the NIPSCO Industrial Group ("Industrial Group") filed a Petition to Intervene, which the Presiding Officers granted in a Docket Entry dated February 16, 2018.[1]

On February 7, 2018, NIPSCO filed corrections to the direct testimony of Katherine A. Cherven and attachments due to a calculation error that resulted in a reduction in the total cost upon which NIPSCO is authorized to earn a return.

[1] For purposes of this Cause, the Industrial Group consists of the following companies: ArcelorMittal USA, BP Energy, Praxair, Inc., USG Corporation, and United States Steel Corporation.

On March 29, 2018, the Indiana Office of Utility Consumer Counselor ("OUCC") filed the testimony of Wes. R. Blakley, Senior Utility Analyst.

The Commission held an evidentiary hearing in this Cause at 1:30 p.m. on April 6, 2018, in Hearing Room 224 of the PNC Center, 101 West Washington Street, Indianapolis, Indiana. NIPSCO, the OUCC, and the Industrial Group appeared at the hearing by counsel, and their respective evidence was admitted without objection. By stipulation, NIPSCO's Objections and Responses to the NIPSCO Industrial Group's Second Set of Data Requests were also admitted.

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

1. **Notice and Jurisdiction.** Notice of the hearing in this Cause was given and published by the Commission as required by law. NIPSCO is a public utility as defined in Ind. Code § 8-1-2-1(a). Under Ind. Code §§ 8-1-2-6.6 and 8-1-2-6.8 and Ind. Code chs. 8-1-8.7 and 8-1-8.8, the Commission has jurisdiction over a public utility's cost recovery related to the use of clean coal technology and other pollution control equipment. The Commission, therefore, has jurisdiction over NIPSCO and the subject matter of this proceeding.

2. **NIPSCO's Characteristics.** Petitioner is a public utility organized under Indiana law with its principal office at 801 East 86th Street, Merrillville, Indiana. NIPSCO owns and operates property and equipment used for the production, transmission, delivery, and furnishing of electric utility service to the public in northern Indiana.

3. **Relief Requested.** In this proceeding, NIPSCO requests approval of revised Environmental Cost Recovery Mechanism ("ECRM") factors to be effective for bills issued during the May 2018 through October 2018 billing cycles, which begin April 30, 2018. NIPSCO also requests approval of proposed modifications to its environmental compliance projects and cost estimates detailed in its Twenty-first Progress Report.

4. **Commission Discussion and Findings.**

A. **Relevant Period.** Ms. Cherven testified that NIPSCO is requesting approval of revised ECRM factors to be applicable to the bills rendered during the May 2018 through October 2018 billing cycles. The ECRM factors include actual capital costs and operating, maintenance, and depreciation expenses in connection with the operation of Petitioner's environmental compliance projects that were in service during the six months ended December 31, 2017, and the recoverable portion (80%) of the MATS Compliance Plan expenses incurred through December 31, 2017. The ECRM factors also include a reconciliation of projected period recoveries of capital cost revenue with actual revenue during the period May 2017 through October 2017 and operating, maintenance, and depreciation revenue with actual revenue during the period May 2017 through October 2017.

B. **Actual Capital Costs.** According to Ms. Cherven, the total cost of environmental compliance projects under construction, net of accumulated depreciation, upon which NIPSCO is authorized to earn a return is $247,358,230. She stated the construction costs include an allowance for funds used during construction ("AFUDC"), computed in accordance with the Federal Energy Regulatory Commission Uniform System of Accounts. Ms. Cherven testified that if the Commission approves the proposed ratemaking treatment for the values shown on Attachment 1, Revised Schedule 1B, to the Verified Petition filed in this Cause ("Attachment 1-A"), NIPSCO will cease accruing AFUDC on those costs because NIPSCO will then be allowed a return on that value and those amounts.

Mr. Baacke testified that Petitioner's Attachment 1-A, Attachment 1, Schedules 1, 1A, and 1B describe Commission-approved environmental compliance projects under construction and on which NIPSCO proposes to earn a return. Schedules 1, 1A, and 1B include a brief description of the projects, approved cost estimates, construction start dates, estimated and actual in-service dates, and prior and current project costs. The costs for the environmental compliance projects have been compiled through December 31, 2017. Mr. Baacke testified all of the projects for which NIPSCO seeks ratemaking treatment in this Cause have been under construction for at least six months.

Based on the evidence presented, the Commission finds NIPSCO's request to begin earning a return on $247,358,230, the value of its environmental compliance projects as of December 31, 2017, net of accumulated depreciation, is reasonable and approves the request.

Ms. Cherven testified that Petitioner's Attachment 1-A, Attachment 1, Revised Schedule 4, page 1 shows NIPSCO's proposed semi-annual capital revenue requirement on its environmental compliance projects at December 31, 2017, is $10,288,191, which is the product of the value of NIPSCO's environmental compliance projects at December 31, 2017, multiplied by the debt and equity components of NIPSCO's weighted cost of capital grossed up for taxes, computing the 12-month and six-month revenue requirement related to the environmental compliance projects. Ms. Cherven sponsored the calculation of NIPSCO's 6.52% weighted average cost of capital at December 31, 2017, which utilizes the methodology the Commission approved in Cause No. 44688.

Ms. Cherven testified Petitioner's Attachment 1-A, Attachment 1, Revised Schedule 4 includes a prior period adjustment to the revenue requirement that relates to: (1) the reconciliation of $14,670 of incorrectly allocated P-Card expenses in NIPSCO's ECR 30 filing, consistent with the Commission's Order in ECR 30, and (2) NIPSCO's calculation of the incremental amount of the return on its investment for the replacement catalyst layer using the estimate of "return on" the original Unit 14 SCR Catalyst 1st Layer included in NIPSCO's rate base in Cause No. 44688. Ms. Cherven explained that Petitioner's Attachment 1-A, Attachment 1, Schedule 8 is a compilation of adjustments based on prior ECR periods showing the calculation of the P-Card expenses that should have been excluded from the Net Plant Additions on Revised Schedule 4, Line 1 by filing period (ECR 28, ECR 29, and ECR 30) in order to capture the correct revenue requirement adjustment. She explained that an additional adjustment related to ECR 30 resulted from a change in the excluded net book value for Schahfer Unit 14 SCR Catalyst 1st Layer from $1,090,846 used in ECR 30 to $1,385,318, which is used in this filing. Ms. Cherven testified the total adjustment amount, which reduced the current revenue requirement on Attachment 1-A, Attachment 1, Revised Schedule 4, is $11,034.

Ms. Cherven testified the federal income tax rate used in computing the revenue requirement is the 21% corporate rate that became effective with passage of the Tax Cuts and Jobs Ace of 2017 ("TCJA"). She stated that as a result of the reduced corporate tax rate, the revenue requirement in this Cause is approximately $1.8 million lower than it would have been if the federal corporate rate remained at 35%. The Industrial Group introduced NIPSCO's responses to data requests as a cross-examination exhibit, contending this exhibit shows the factors approved in ECR 30 were calculated using the 35% tax rate; therefore, NIPSCO over-collected federal income taxes through its ECR 30 factors, and these over-collections should also be applied to reduce the revenue requirement in ECR 31. NIPSCO disagreed, asserting that over-collections in prior ECR cycles should be addressed in Cause No. 45032 rather than through a reduction in the ECR 31 factors.

Mr. Blakley testified that NIPSCO corrected the error the OUCC found in ECR 30 by removing $14,670 from the cost of Unit 12 FGD, as well as correcting similar errors in ECR 29 and ECR 28. He testified these errors totaled $34,211 and stated the erroneous charges to Unit 12 FGD over the past three ECR filings led to an over-recovery of NIPSCO's revenue requirement. In this filing, Mr. Blakley stated that NIPSCO reduced its revenue requirement associated with these errors.

Mr. Blakely testified NIPSCO adjusted its ECR schedules to reflect the reduced federal income tax rate from 35% to 21% but only with respect to the rate change. He testified that other items affected by the tax change will be addressed as a result of the Commission's investigation into the impacts of the TCJA and its possible rate implications in Cause No. 45032.

Based on the evidence presented, the Commission finds that NIPSCO's proposed adjusted semi-annual capital revenue requirement of $10,288,191 is reasonable and approves the capital revenue requirement. In so finding, the Commission rejects the proposition that NIPSCO's revenue requirement for ECR 31 should be reduced by estimated federal income tax over-collections in ECR 30. These are estimated amounts outside the normal reconciliation period for ECR 31, and at this time, such over-collections are a regulatory asset to be addressed in Phase 2 of Cause No. 45032.

C. <u>Actual Operation and Maintenance ("O&M") Expenses</u>. Mr. Walter testified that as shown on Petitioner's Attachment 1-A, Attachment 2, Schedule 1, page 2 (lines 1 through 16), for the period July through December 2017, NIPSCO incurred $2,740,006 of actual O&M expenses associated with NIPSCO's ownership and operation of the environmental compliance projects (capital projects) and recoverable federally mandated MATS Compliance Plan O&M projects, of which $93,357 was fixed, and $2,646,649 was variable.

1. <u>Environmental Compliance Projects</u>. Mr. Walter identified the breakdown of actual O&M expenses incurred during the July through December 2017 period as shown on Petitioner's Attachment 1-A, Attachment 2, Schedule 1, page 2. Mr. Walter testified there were no noteworthy O&M expense increases during the period July through December 2017, and no new O&M expense categories were created since the O&M expenses approved in Cause No. 42150 ECR 30.

2. <u>MATS Compliance Plan O&M Projects</u>. Mr. Walter testified that in the Order in Cause No. 44311 ("44311 Order"), the Commission approved the following federally mandated O&M projects as part of NIPSCO's MATS Compliance Plan: (1) Precipitator and FGD Mist Eliminator Cleaning for Bailly Units 7 and 8; (2) ESP Flow Modeling for Schahfer Unit 15; and (3) Air Testing for Schahfer Units 14, 15, 17, and 18. In Cause No. 42150 ECR 24, the Commission approved a federally mandated O&M project for Unit 15 ESP Flow Modifications. Mr. Walter indicated that during the period July through December 2017, there is a credit of $4,762 which is a final true-up of estimated costs to actual costs related to the ESP Flow Modifications for Schahfer Unit 15.

Based on the evidence presented, the Commission finds that NIPSCO's actual O&M expenses associated with NIPSCO's environmental compliance projects (capital projects) and recoverable federally mandated MATS Compliance Plan O&M project expenses for the period ending December 31, 2017, of $2,740,006 are reasonable and approves recovery of such expenses through the ECRM.

D. Actual Depreciation Expense. Petitioner's Attachment 1-A, Attachment 2, Schedule 1, page 1 shows NIPSCO's actual depreciation expense for the six months ending December 31, 2017, was $6,857,501. Ms. Cherven testified that the actual depreciation expense consists of depreciation expenses associated with NIPSCO's ownership and operation of the environmental compliance project facilities that have been placed in service. She explained that the actual depreciation expense was computed based on the depreciation lives and/or rates approved in Cause Nos. 44688, 42150, 44012, and 44311.

Based on the evidence presented, the Commission finds that NIPSCO's actual depreciation expense for the six months ending December 31, 2017, of $6,857,501 has been properly calculated and is reasonable; therefore, the Commission approves the actual depreciation expense for recovery through the ECRM.

E. Allocation of Actual Capital Costs, O&M, and Depreciation Expenses. Ms. Cherven sponsored Petitioner's Attachment 1-A, Attachment 1, Schedule 5 showing the demand allocation percentages and Attachment 2, Schedule 1, page 3 showing the demand and energy allocation percentages attributable to each of NIPSCO's rate schedules as approved in the 44688 Order. The demand allocators approved for purposes of the ECRM adjustment were set forth in Joint Exhibit B to the Stipulation and Settlement Agreement approved in the 44688 Order. Ms. Cherven testified NIPSCO has adjusted its demand and energy allocation percentages in this filing to reflect the migration of customers.

Based on the evidence presented, the Commission finds that NIPSCO's proposed ECRM allocation factors are reasonable, the ECR costs have been properly allocated, and such allocations are approved.

F. Reconciliation of Actual Capital Costs, O&M, and Depreciation Expenses. Ms. Cherven sponsored Petitioner's Attachment 1-A, Attachment 1, Schedule 6 showing NIPSCO's reconciliation of projected period recoveries of ECRM revenue with actual revenue during the period May 2017 through October 2017. NIPSCO's total computed under- or over-recoveries of ECRM revenue for this period are reflected in Column D, which in this Cause shows an over-recovery of $405,282.

Ms. Cherven also sponsored Petitioner's Attachment 1-A, Attachment 2, Schedule 2 showing NIPSCO's reconciliation of projected expense revenue with actual expense revenue during the period May 2017 through October 2017. NIPSCO's total computed under- or over-recoveries of expense revenue for this period are reflected in Column D, which in this Cause shows an over-recovery of $771,797.

Based on the evidence presented, the Commission finds NIPSCO properly included a reconciliation of May 2017 through October 2017 over-recoveries to be reflected in the ECRM 31 factors.

G. <u>Deferred Federally Mandated Costs</u>. Ms. Cherven testified that Petitioner's Attachment 1-A, Attachment 2, Revised Schedule 1A shows the detail of all expenses incurred in connection with NIPSCO's federally mandated MATS Compliance Plan O&M projects. She testified that in accordance with the 44311 Order and Ind. Code § 8-1-8.4-7(c), NIPSCO will defer, as a regulatory asset on the balance sheet, 20% of all costs associated with the approved projects, including post in-service carrying charges on the deferred O&M expenses, for recovery in NIPSCO's next general rate case. Petitioner's Attachment 1-A, Attachment 2, Schedule 3 reflects the deferred federally mandated costs and the ongoing carrying charges on those deferred costs.

Based on the evidence presented and pursuant to the 44311 Order and Ind. Code § 8-1-8.4-7(c)(2), the Commission authorizes NIPSCO to defer 20% of the federally mandated costs incurred in connection with the federally mandated MATS Compliance Plan O&M projects and recover those deferred costs in Petitioner's next general rate case. The Commission also authorizes NIPSCO to record ongoing carrying charges based on the current overall weighted average cost of capital on all deferred federally mandated costs until the deferred federally mandated costs are included for recovery in NIPSCO's base rates as allowed by Ind. Code § 8-1-8.4-7(c)(2).

H. <u>Semi-Annual Revenue Requirement</u>. Ms. Cherven testified that Petitioner's Attachment 1-A, Attachment 3, Revised Schedule 1 summarizes the capital and expense revenue requirements calculated in Attachments 1 and 2. NIPSCO's proposed total revenue requirement on its environmental compliance projects at December 31, 2017, is $18,841,873. The capital revenue requirement is the sum of the requested capital revenue requirement of $10,288,191 minus an amount of $405,282 from the capital cost reconciliation, for a total capital revenue requirement of $9,882,909 for the billing period of May 2017 through October 2018.

The expense revenue adjustment, as shown on Petitioner's Attachment 1A, Attachment 2, Schedule 1, page 4, is the sum of Petitioner's requested O&M expense of $2,740,006 and depreciation expense of $6,857,501, decreased by $771,797 from the expenses reconciliation, for a total expense revenue requirement of $8,825,710. Ms. Cherven testified that Column E on Petitioner's Attachment 1-A, Attachment 3, Revised Schedule 1 shows the total revenue requirement which NIPSCO seeks to recover in this Cause, with the forecasted kWh sales for the billing period applied to calculate the billing factors shown in Column G.

Based on the evidence presented, the Commission finds that NIPSCO's proposed adjusted semi-annual revenue requirement of $18,841,873 is reasonable and approves the revenue requirement.

I. **New ECRM Factors.** Ms. Cherven sponsored Petitioner's Attachment 1-A, Attachment 4, showing the proposed ECRM factors and explained how the ECRM factors were developed. She testified the estimated average monthly bill impact for a typical residential customer using 698 kWh per month is $2.07, which is a decrease of $0.88 from what a customer has paid using the currently approved ECRM factor. Ms. Cherven testified the estimated average monthly bill impact for a typical residential customer using 1,000 kWh per month is $2.96, which is a decrease of $1.26 from what a customer has paid using the currently approved ECRM factor.

Based on the evidence presented, the Commission approves the proposed ECRM factors set forth in Petitioner's Attachment 1-A, Attachment 3, Revised Schedule 1 to be applicable for bills rendered during the billing cycles of May 2018 through October 2018, to remain in effect until a different ECRM adjustment is approved in a subsequent filing.

5. **Commission Findings and Conclusions Regarding Progress Report.** In its November 26, 2002 Order in Cause No. 42150, the Commission approved NIPSCO's proposal that the Commission maintain an ongoing review of NIPSCO's environmental compliance project construction and expenditures and that NIPSCO annually submit to the Commission a report of any revisions of the plan and cost estimates for such construction ("Progress Report"). In its August 25, 2010 Order in Cause No. 43526, the Commission ordered NIPSCO to file the Progress Reports on the status of environmental compliance projects tracked in the ECRM as part of Petitioner's ECRM filings. In its December 28, 2011 Phase I Order in Cause No. 44012, the Commission approved NIPSCO's request to file semi-annual Progress Reports (as opposed to annual) as part of the ongoing review process under Ind. Code § 8-1-8.7-7. In addition, in the 44311 Order, the Commission authorized NIPSCO to seek timely recovery of the MATS Compliance Plan projects as part of NIPSCO's semi-annual Progress Reports filed in ECR proceedings and to provide updates to the MATS Compliance Plan capital projects through the semi-annual ECRM proceedings.

Pursuant to the ongoing review process under Ind. Code § 8-1-8.7-7 and as approved in the 44311 Order, NIPSCO requests approval of its Twenty-first Progress Report on the status of environmental compliance projects tracked in the ECRM and approval to recover the revised costs of its environmental compliance projects through the ECRM. Mr. Baacke testified that since NIPSCO's Twentieth Progress Report approved in Cause No. 42150 ECR 30, NIPSCO has identified aspects of its Compliance Plan that require further modification. Mr. Baacke sponsored Attachment PR to Petitioner's Attachment 1-A. Attachment PR sets forth NIPSCO's Compliance Plan containing the NOx Compliance Plan, Multi-Pollutant Compliance Plan, and MATS Compliance Plan highlighted to show proposed modifications. He testified the modifications consist of scheduling changes and changes in estimated costs.

As to the scheduling changes, Mr. Baacke testified the in-service dates for the Unit 12 SCR Catalyst 1st Layer and Unit 12 SCR Catalyst 2nd Layer were revised to reflect the actual in-service dates, and Unit 12 SCR Catalyst 3rd Layer and Unit 14 SCR Catalyst 2nd Layer were revised to reflect the estimated construction start and in-service dates.

With respect to the changes in estimated costs, Mr. Baacke testified final project costs for the Unit 12 ACI System, Unit 14 ACI System, Unit 12 Fuel Additive, Unit 14 Fuel Additive, and

Unit 15 Fuel Additive projects have been revised to reflect actual expenditures, resulting in a decrease of $2,295,471 from NIPSCO's Twentieth Progress Report.

Based on the evidence presented, the Commission finds the Twenty-first Progress Report is reasonable; therefore, the Commission approves the proposed modifications to the Compliance Plan and authorizes NIPSCO to recover these costs through its ECRM, including ratemaking treatment for the catalyst layer projects consistent with the October 16, 2013 Order in Cause No. 42150 ECR 21.

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

1. NIPSCO is authorized to implement the rate adjustments reflecting the recovery of capital costs, O&M, and depreciation expenses identified above in Petitioner's rates and charges for electric service in accordance with NIPSCO's ECRM beginning with the May 2018 billing cycle, to remain in effect until replaced by a different ECRM adjustment approved in a subsequent filing.

2. Prior to implementing the approved ECRM factors, NIPSCO shall file the tariff and applicable rate schedules under this Cause for approval by the Commission's Energy Division. Such rate(s) shall be effective for bills NIPSCO renders commencing with the May 2018 billing cycle subject to Division review and agreement with the amounts reflected.

3. NIPSCO is authorized to defer 20% of the federally mandated costs incurred in connection with the federally mandated MATS Compliance Plan O&M projects and recover those deferred costs in its next general rate case, and NIPSCO is authorized to record ongoing carrying charges based on the current overall weighted average cost of capital on all deferred federally mandated costs until the deferred federally mandated costs are included for recovery in NIPSCO's base rates in its next general rate case.

4. Pursuant to Ind. Code § 8-1-8.7-7 and as approved in Cause No. 44311, NIPSCO's modified Compliance Plan, as set forth in the Twenty-first Progress Report, is approved.

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

HUSTON, FREEMAN, OBER, WEBER, AND ZIEGNER CONCUR:

APPROVED: APR 25 2018

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

Mary M. Becerra

Mary M. Becerra
Secretary of the Commission

ORIGINAL

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

IN THE MATTER OF THE COMMISSION'S INVESTIGATION, PURSUANT TO IC § 8-1-2-58 INTO THE STATUS OF THE TRANSFER OF FUNCTIONAL CONTROL OF TRANSMISSION FACILITIES LOCATED IN INDIANA, BY NORTHERN INDIANA PUBLIC SERVICE COMPANY, TO A REGIONAL TRANSMISSION ORGANIZATION AND FOR COMMISSION REVIEW OF THE TRANSFER PURSUANT TO IC § 8-1-2-83	)	CAUSE NO. 42349 APPROVED: SEP 24 2003

BY THE COMMISSION:
David E. Ziegner, Commissioner
Scott R. Storms, Chief Administrative Law Judge

On December 19, 2002, the Indiana Utility Regulatory Commission ("Commission" "Indiana Commission" or "IURC") approved an Order that instituted an investigation, docketed as Cause No. 42349, regarding the status of the transfer of functional control of transmission assets located in Indiana by Northern Indiana Public Service Company ("NIPSCO") to a regional transmission organization, and for Commission review of the transfer pursuant to Ind. Code. (IC) § 8-1-2-83. On January 28, 2003, the Presiding Officers issued a Docket Entry in which they advised the Parties that the Commission had designated Dr. Bradley K. Borum and Ms. Laura L. Cvengros of the Commission's Electricity Division to appear as testimonial staff ("Testimonial Staff") in this matter.

Pursuant to notice, duly published as required by law, an Evidentiary Hearing was conducted on July 7, 2003, commencing at 9:30 a.m. EST, in Room TC-10 of the Indiana Government Center South, 302 West Washington Street, Indianapolis, Indiana, at which time the Parties' testimony and exhibits were offered and admitted into evidence and the witnesses were cross-examined. NIPSCO presented the testimony of Frank A. Venhuizen, Director, Electric Transmission and Market Services for NIPSCO; and, William M. O'Malley, Vice President, Finance for NIPSCO. Mr. James P. Torgerson, President and Chief Executive Office, Midwest Independent Transmission System Operator, Inc., ("MISO" or "Midwest ISO") also testified in support of NIPSCO's request. Intervenor, GridAmerica LLC, ("GridAmerica") presented the testimony of Paul J. Halas, Senior Vice President and General Counsel for GridAmerica. The Indiana Office of the Utility Consumer Counselor ("OUCC") presented the testimony of Peter M. Boerger, Assistant Director of the Electric Division for the OUCC. The Commission's Testimonial Staff submitted the testimony of John D. Chandley, a Principal, at LECG, an economic and management consulting firm; Bradley K. Borum, Director IURC Electricity Division; and, Laura Cvengros, Assistant Director, IURC Electricity Division. Members of the general public were present at the Evidentiary Hearing.

Based upon the applicable law and the evidence herein, and being duly advised in the premises, the Commission now finds as follows:

1. **Notice and Jurisdiction**. Due, legal and timely notice of the Evidentiary Hearing in this Cause was given as required by law. NIPSCO is a public utility under IC § 8-1-2-1, and is subject to the Commission's jurisdiction in accordance with the Public Service Commission Act, as amended, and other laws of the State of Indiana.

2. **Petitioner's Characteristics and Business**. NIPSCO is a public utility corporation organized and existing under the laws of the State of Indiana, having its principal office at 801 E. 86th Avenue, Merrillville, Indiana. NIPSCO is engaged in rendering electric utility service to the public in the State of Indiana and owns, operates, manages and controls plant and equipment within the State of Indiana used for the production, transmission, delivery and furnishing of electric utility service. NIPSCO currently supplies electric energy to approximately 430,000 customers in 21 counties in the northern part of Indiana. The territory in which NIPSCO provides electric service covers approximately 12,000 square miles and has a population of 2.2 million. NIPSCO owns and operates four coal-fired electric generating stations, two hydroelectric generating plants, and four gas-fired combustion turbines providing a total system net capability of 3,392 megawatts. NIPSCO's transmission system consists of approximately 3,066 circuit miles of line, including 354 circuit miles of 345 kV line, 759 miles of 138 kV line, 1,529 miles of 69 kV line, and 245 miles of 34.5 kV line.

3. **Background.** The history, rationale and benefits behind the Federal Energy Regulatory Commission's ("FERC") efforts to transition to a competitive wholesale power market are summarized in the FERC's order *In Re Regional Transmission Organizations*, issued December 20, 1999, 89 FERC ¶ 61,285 ("Order No. 2000").[1] Therein, the FERC found that "traditional management of the transmission grid by vertically integrated electric utilities was inadequate to support the efficient and reliable operation that is needed for the continued development of competitive electricity markets . . . ." Order No. 2000 at 2. The FERC concluded that "independent regionally operated transmission grids will enhance the benefits of competitive electricity markets" and that "[c]ompetition in wholesale electricity markets is the best way to protect the public interest and ensure that electricity consumers pay the lowest price possible for reliable service." *Id.* at 3.

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1. *See*, Regional Transmission Organizations, Order No. 2000, 65 Fed. Reg. 809 (January 6, 2000), FERC Stats. & Regs. P31,089 (1999) (Order No. 2000), order on reh'g, Order No. 2000-A, 65 Fed. Reg. 12,088 (March 8, 2000), FERC Stats. & Regs. P31,092 (2000) (Order No. 2000-A), aff'd sub nom. Public Utility District No. 1 of Snohomish County, Washington v. FERC, 272 F.3d 607 (D.C. Cir. 2001).

In Order No. 2000, the FERC, while strongly encouraging each transmission-owning utility to join a Regional Transmission Organization ("RTO"), recognized that there continues to be important transmission-related impediments to a competitive wholesale electric market. These impediments include the engineering and economic inefficiencies inherent in the current operation and expansion of the transmission grid and the continuing opportunities for transmission owners to unduly discriminate in the operation of their transmission systems to favor their own, or their affiliates' power marketing activities. The engineering and economic inefficiencies the FERC identified and sought to address in Order No. 2000 resulted from the lack of regional coordination of an interconnected transmission grid. The FERC concluded that a properly structured RTO could provide significant benefits in the operation of the transmission grid. *Id.* at 70. A successful RTO would, through transmission grid management, improve grid reliability, remove remaining opportunities for discriminatory transmission practices, improve market performance, and facilitate lighter handed regulation. *Id.* at 71. These efficiencies would include, among other things: regional transmission pricing; improved congestion management of the grid; more accurate total transmission capability ("TTC") and available transmission capability ("ATC") calculations; more effective management of parallel path flows; and, reduced transaction costs. *Id.* at note 99.

In order for an RTO to adequately address regional operational and reliability issues, the FERC stated in Order No. 2000 that, at a minimum, an RTO must satisfy four characteristics: 1)independence; 2) scope and regional configuration; 3) operational authority; and, 4) short-term reliability. In addition, the RTO would be required to perform eight functions: 1) tariff administration and design; 2) congestion management; 3) parallel path flow; 4) ancillary services; 5) Open Access Same Time Information System ("OASIS") and TTC and ATC; 6) market monitoring 7) planning and expansion; and, 8) interregional coordination. *Id.* at 152, 323-24.

4. <u>Requests for Approval from FERC and the Indiana Commission</u>. On June 3, 1999, NIPSCO and several other utilities petitioned FERC for approval to form the Alliance RTO. On June 29, 2001, in Cause No. 42032, the Indiana Michigan Power Company ("I&M") and NIPSCO filed a joint petition requesting approval to transfer functional control of transmission facilities located within the State of Indiana to the Alliance Regional Transmission Organization ("Alliance RTO" or "ARTO").

In response to the request of NIPSCO and others to form the Alliance RTO, the FERC, in a series of orders, repeatedly attempted to provide input regarding the steps necessary for the proper formation and development of the Alliance RTO. Through its Orders, FERC identified the steps that the Alliance RTO had taken to comply with Order 2000, and also identified the specific shortcomings the Alliance RTO had with respect to its efforts to demonstrate compliance with Order 2000. Following repeated efforts to encourage the Alliance RTO to address the shortcomings identified by FERC, on December 20, 2001, in 97 FERC ¶ 61,327 ("December 20, 2001 Order"), the FERC determined that the proposal presented by the Alliance RTO failed to demonstrate compliance with the specific enumerated requirements set forth in Order No. 2000. Three days prior to the

December 20, 2001 Order issued by FERC, the Indiana Commission issued an Order in Cause No. 42032 in which we denied NIPSCO and I&M's request for approval to transfer functional control of transmission facilities located in Indiana to the Alliance RTO. *In Re Joint Petition of Indiana Michigan Power Company, d/b/a/American Electric Power and Northern Indiana Public Service Company,* Cause No. 42032 (consolidated with 42027) (*Ind. Util. Reg. Comm'n,* December 17, 2001) ("December 17, 2001 Order").

In our December 17, 2001, Order, we recognized that, "[b]efore allowing Indiana utilities to transfer functional control of transmission assets to an RTO, the Commission must find that the evidence demonstrates that such transfer will be to an entity that will provide reliable, adequate and efficient service to Indiana customers and those who serve them. The record here does not support such a finding." December 17, 2001 Order, at 33-34. The Commission further indicated that "[t]he Alliance Companies have worked on this matter for several years....[and have had] ample time to produce an independent governance structure..."*Id.* at 34. "The Alliance Companies' inability now to make business decisions due to the lack of independence is reason to question their assertion of commitment to independence, not give them more time to support that assertion." *Id.* By rejecting the Joint ARTO Petitioners' Application, we do not mean to suggest that the status quo, in which NIPSCO and I&M are not members of any RTO, is satisfactory....[T]he public interest requires seamless generation markets, and the transfer of operational control of transmission assets to a properly designed RTO is a prerequisite to seamlessness.... Implicit in the foregoing explanation is our expectation that... NIPSCO will not maintain the status quo, in which they have not transferred their transmission assets to any RTO. We expect that either voluntarily, as a result of an eventual FERC mandate or as a result of a mandate from this Commission, they will make such a transfer. To make certain that such a transfer does occur and occurs in a manner consistent with the public interest, we will be initiating a separate investigation, to examine the alternative courses of action practically available to the Joint Petitioners." *Id.* The Commission investigation in this Cause was initiated in accordance with the directives set forth in our December 17, 2001 Order.

Following its unsuccessful effort to join the Alliance RTO, NIPSCO explored other alternatives, including joining the MISO, either as an individual transmission owner, or as part of an Independent Transmission Company ("ITC"). NIPSCO ultimately chose to pursue membership in MISO as part of an ITC.

5. **<u>Nature of the Case</u>**. In this proceeding, NIPSCO seeks Commission approval to transfer functional control of operation of certain of their electric transmission facilities to the Midwest ISO through membership in Grid America which is a wholly owned subsidiary of National Grid USA ("National Grid"). The facilities in question are all 69 KV and above systems for NIPSCO. The facilities are integral to the provision of adequate and reliable electric service to retail customers in Indiana.

6. **Legal Overview of Requested Relief**. The Petitioner in this proceeding seeks Commission approval to transfer control of certain transmission assets as provided under IC § 8-1-2-83(a), which states, *inter alia*, that:

> No public utility, as defined in section 1 of this chapter, shall sell, assign, transfer, lease, or encumber its franchise, works, or system to any other person, partnership, limited liability company, or corporation, or contract for the operation of any part of its works or system by any other person, partnership, limited liability company, or corporation, without the approval of the commission after hearing.

The provisions set forth in IC § 8-1-2-83, are intended to ensure that Commission approval is granted before a utility may be operated or controlled by any person other than the person that is licensed or permitted to do so. *Illinois-Indiana Cable TV v. Public Service Comm'n,* 427 N.E. 2d 1100, 1108 (Ind. App. 1981). In enacting the foregoing provision, the Legislature intended the Commission to regulate public utility transfers "in the interest of public welfare." *See, In re N.W. Ind. Tel. Co.*, 171 N.E. 65 (Ind.1930). Explaining the purpose of the transfer approval legislation, the court stated:

By [Section 95, predecessor to IC 8-1-2-83], the Legislature undertook to supervise the sale of public utility property in the interest of the public by providing a means for the investigation of the proposed sale in advance of its consummation. Such investigation necessarily has to do with the effect in the future on public convenience and necessity....One of the reasons for this statute, and there may be many more, is to protect the public in the use of utility service with as little inconvenience as may be essentially necessary to furnish the same.

In re N.W. Ind. Tel. Co. 171 N.E. at 71.

Consistent with the foregoing analysis, the Commission has applied the public interest standard of review in numerous proceedings and determined that: "[I]n reaching a decision to approve a purchase or sale of utility property, the Commission's threshold inquiry must be whether or not that proposed purchase and sale is in the public interest." *See, In Re Joint Petition Indiana Michigan Power Company, d/b/a/American Electric Power,* Cause No. 42032; *Joint Petition of Hoosier Energy, et al*, Cause No. 42027 (*Ind. Util. Reg. Comm'n,* December 17, 2001); *In the Matter of the Joint Petition of Commonwealth Edison Company of Indiana, State Line Energy L.L.C and Commonwealth Edison Company*, Ind. Util. Reg. Comm'n, Cause No. 40575, (December 18, 1996), citing *Indiana ex rel Indianapolis Traction & Term Co. v. Lewis* 120 N.E. 129 (1918).

Also, as we determined in our December 17, 2001 Order in Cause No. 42027 and 42032, in considering whether a transfer satisfies the public interest test of IC 8-1-2-83, the Commission must look to other statutes. The combination of Commission decisions under IC § 8-1-2-83, and decisions under other statutes, yields a set of public interest factors with direct application to this cause.

A. <u>Reliability</u>: The Commission is charged with ensuring that a utility provide reliable service and facilities. *See*, IC 8-1-2-4 (each utility "is required to furnish reasonably adequate service and facilities"); *Office of Util. Consumer Counselor v. PSI, Inc.*, 463 N.E. 2d 499, 503 (Ind. Ct. App. 1984)(finding that the Commission..."was established to insure that public utilities provide constant, reliable and efficient service to customers...."); *Indiana Michigan Power Company, Ind. Util. Reg. Comm'n*, Cause No. 41982 (July 27, 2001), (approving sale of a transmission facility in part because the transfer would "result in the improvement of transmission facilities and provide for customer load growth");

B. <u>Financial Viability</u>: *See, Commonwealth Edison of Indiana, Ind. Util. Reg. Comm'n*, Cause No. 40575 (December 18, 1996), (approving the transfer of certain assets and inventory because the transferee had significant experience in the business of operating coal-fired generating stations and had the necessary financial strength and experience to operate the project); *Investigation into the Operation of Arlington Utilities, Ind. Util. Reg. Comm'n*, Cause No. 41540 (March 29, 2001), (reviewing financial viability of transferee to consummate purchase of water utility's assets);

C. <u>Impact on Competition</u>: *See, Ameritech Communications Inc., and Williams Communications, Inc., Ind. Util. Reg. Comm'n*, Cause No. 41678, (August 2, 2000), (In which the Petitioners sought approval to transfer assets under IC § 8-1-2-83, and in which the Commission found that system enhancements resulting from asset transfer will lead to increased competition);

D. <u>Impact on Efficiency and Rates</u>: IC §§ 8-1-2-58 and 8-1-2-69, allow the Commission to conduct an investigation if it believes that any rate or charge may be unreasonable or unjustly discriminatory or if it believes that any service may be inadequate, in order to determine if such act, practice, or service is just and reasonable. *See also, Ameritech, Id.* (finding that the transfer would allow for "system-wide consistency in the method of providing services and will result in a better utilization of resources and streamlined operations which will benefit the public");

E. <u>Access to Information</u>: IC § 8-1-2-48 requires that the Commission have access to "all necessary information to enable the commission to perform its duties."

These public policy concerns -- reliability, financial viability, competition, efficiency and rates, and access to information -- are all implicated by the proposals in this case, and consistent with prior determinations made by this Commission, will be fully discussed in this Order vis-à-vis the proposal presented by NIPSCO.

7. **Evidence Presented by the Parties.**

A. ***The Petitioner's Direct Evidence.*** Mr. Venhuizen stated in his testimony that NIPSCO decided to join the Midwest ISO as a member of GridAmerica, and explained that GridAmerica will be an ITC pursuant to Attachment I of the Midwest ISO Open Access Transmission Tariff ("OATT"). Venhuizen Direct at 3. Mr. Venhuizen explained that GridAmerica is an independent entity that does not participate in wholesale or retail energy markets and does not generate, buy or sell energy. In a May 28, 2002, filing with FERC, NIPSCO indicated that it planned to join the Midwest ISO through membership in an ITC. *Id.*

Mr. Venhuizen indicated that the GridAmerica participants are Ameren Services Company ("Ameren"), First Energy Corporation ("First Energy"), and NIPSCO (jointly referred to as the "GridAmerica Participants", "Grid America Companies" or "Grid America Three"). *Id.* at 3-4. Mr. Venhuizen noted that the Midwest ISO has been involved in the formation of GridAmerica, and has been a leader in facilitating the formation and operation of ITCs under its umbrella. *Id.* at 4. According to Mr. Venhuizen, the Midwest ISO's support for ITCs was critical to NIPSCO's decision to pursue membership in the MISO. *Id.*

Mr. Venhuizen stated he believes that GridAmerica, with National Grid as the managing member, may well be able to attract the capital needed to upgrade transmission facilities. According to Mr. Venhuizen, National Grid is an experienced and proven manager of transmission systems and will operate NIPSCO's transmission assets reliably and efficiently. Mr. Venhuizen testified that National Grid's expertise in transmission system operations, and its proven ability to attract capital, will greatly enhance the overall reliability of NIPSCO's transmission grid. *Id.*

Mr. Venhuizen testified that the level and quality of NIPSCO's retail service will be the same or better as a result of its decision to join GridAmerica, and the price of NIPSCO's retail service will be unaffected by GridAmerica's operations. *Id.* at 6. He stated that NIPSCO will be able to obtain transmission service over the GridAmerica facilities in the same way it would obtain any transmission service or transmission facility within the Midwest ISO footprint. He also indicated that NIPSCO's retail customers should benefit from National Grid's expertise. *Id.*

During cross-examination, Mr. Venhuizen stated that the Midwest ISO, along with the GridAmerica Participants, submitted a rate and tariff filing to FERC on February 28, 2003, which uses NIPSCO's existing transmission rate as a license plate rate for deliveries into the NIPSCO zone. As a future transmission customer of GridAmerica and the Midwest ISO, NIPSCO will be required to pay the appropriate base zonal rate for service delivered within the Midwest ISO. In addition, customers taking service from the Midwest ISO must pay the Midwest ISO Schedule 10 Cost Adder. This adder permits the Midwest ISO to recover its administrative costs. According to Mr. Venhuizen, the Schedule 10 Adder will not increase as a result of the formation and operation of GridAmerica. *Id.* at 6-7.

Mr. Venhuizen stated that there are four (4) agreements that will govern the formation and operation of GridAmerica, each of which has been filed with the FERC. The first agreement, executed by GridAmerica and the Midwest ISO is an Appendix I ITC Agreement ("ITC Agreement"). The second, which is signed by GridAmerica and National Grid, is an LLC Agreement ("LLC Agreement"). The third, signed by Ameren, FirstEnergy, NIPSCO, and National Grid is a Master Agreement ("Master Agreement"). The fourth, signed by Ameren, FirstEnergy, NIPSCO and GridAmerica is an Operating Agreement ("Operating Agreement"). *Id.* at 7.

Mr. Venhuizen testified that the ITC Agreement is intended to govern the relationship between the Midwest ISO and GridAmerica, and was negotiated and drafted pursuant to the terms of Appendix I of the Midwest ISO Tariff. *Id.* at 9. Pursuant to Article 2, the initial term of the ITC Agreement is three years and may be extended from year to year unless any party provides the other with six months notice of termination.[2] Articles 3 and 4 of the ITC Agreement describe the relationship between the Midwest ISO and GridAmerica. Under Article 3 of the ITC Agreement, GridAmerica will be treated as a transmission owner pursuant to the Midwest ISO Agreement and the GridAmerica Three will have the same rights and voting authority as Midwest ISO transmission owners. *Id.* Pursuant to Article 4, the GridAmerica Three will transfer functional control of their transmission facilities to GridAmerica which will, in turn, cede certain functions to the Midwest ISO. *Id.* Schedule 5 of the ITC Agreement specifically delineates the functions that will be carried out by GridAmerica and those that fall within the purview of the Midwest ISO. *Id.* at 9-10.

According to Mr. Venhuizen, Article 5 of the ITC Agreement requires GridAmerica, and the Midwest ISO, to execute an Agency Agreement permitting the Midwest ISO to use, if necessary, the distribution facilities of the GridAmerica Companies in order to provide transmission service. *Id. at 10.* Article 5 of the ITC Agreement also requires the Midwest ISO to provide transmission services to entities that have agreements with the GridAmerica Three, for the provision of open access transmission service for customers with agreements that pre-date the OATTs of the GridAmerica Participants ("Grandfathered Contracts"). *Id.* Mr. Venhuizen believes that existing customers will receive the same transmission service from the Midwest ISO as they currently receive from NIPSCO. *Id.*

Mr. Venhuizen testified that Article 7 of the ITC Agreement provides that the Midwest ISO will pay either GridAmerica or the GridAmerica Three any amounts due for transmission facilities controlled by GridAmerica in the same way that it pays similar revenues to other Midwest ISO transmission owners. *Id.* at 11. Article 7 of the ITC Agreement also requires the Midwest ISO to either discount its through and out rate, or make a Section 205 filing to lower that rate, in order to enhance competition. *Id.* Mr. Venhuizen indicated that Article 10 of the ITC Agreement states that the Midwest ISO is responsible for market monitoring and has full and complete authority for market monitoring within its footprint. *Id.* at 12. Article 13 of the ITC Agreement obligates the Midwest

2. In Cause 101 FERC ¶ 61,320, (December 19, 2002), the FERC required the GridAmerica Three to remain members of the Midwest ISO for five years. The GridAmerica Participants have made a compliance filing with the FERC indicating that the GridAmerica Three will agree to remain members of the Midwest ISO for five years.

ISO to reimburse the GridAmerica Three for all costs incurred to form GridAmerica as an operational ITC. *Id.* The Midwest ISO will also pay National Grid $12 million per year to act as its managing member of GridAmerica and for consulting services. In addition the Midwest ISO will reimburse --up to a cap of $36.2 million-- the Grid America Three for costs incurred in their efforts to form the Alliance RTO. *Id.*

In addition, the LLC Agreement obligates the GridAmerica Three to pay National Grid $3.5 million for the first three years of the initial term and $2.5 million for the 4th and 5th years of the initial term.[3] After the initial term, National Grid's compensation will be adjusted for inflation. *Id.* at 16. Mr. Venhuizen stated that the GridAmerica Participants agreed that the obligation to pay GridAmerica should be based upon respective net plant levels, in that NIPSCO's net plant level was far smaller than that of Ameren and FirstEnergy. *Id.* The agreement provides for an initial term of five years, but permits any GridAmerica Participant to leave GridAmerica after three years. However, Mr. Venhuizen indicated that the parties have modified this condition and the Grid America Three have made a compliance filing with FERC in which they agreed to remain with MISO for five years. *Id.* at 16-17.

Mr. Venhuizen also described the provisions of the LLC Agreement applicable to the formation, governance, and financing of GridAmerica. He said that GridAmerica was formed as a Delaware Limited Liability Company and has two classes of members, Class A and Class B unit holders. *Id.* at 13. Class A units may only be held by parties meeting FERC's independence standards. Class B units may be held by market participants. In general, only Class A unit holders may vote on issues affecting GridAmerica. Class B unit holders may, in limited circumstances, vote on issues that directly affect their investments such as bankruptcy filings, mergers, and acquisitions. Class A units are currently only held by the initial member of GridAmerica.[4] *Id.* GridAmerica does not currently have any Class B unit holders. *Id.* at 14. In the event that a transmission owner divests all or part of its assets to GridAmerica, that transmission owner will receive Class B units as part of the transfer price.[5] *Id.* As non-divesting transmission owners, the GridAmerica Three play no role in GridAmerica governance and do not hold ownership interests (or units) in GridAmerica. The role of the GridAmerica Three in the operation of GridAmerica is governed by the Operation Agreement. *Id.* Mr. Venhuizen stated that National Grid is committed to invest up to $500 million to purchase transmission assets for GridAmerica and has agreed to set aside $200 million of the $500 million necessary to purchase the transmission assets of the GridAmerica Three. *Id.* at 15.

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3. While testimony was presented on this issue, it was not considered by the Commission as part of this Cause.

4. The initial member of GridAmerica is GridAmerica Holdings LLC, a wholly owned subsidiary of National Grid.

5. Mr. Venhuizen indicated that as transmission and generation owners are market participants, they may only hold Class B units in GridAmerica.

Under the Master Agreement, National Grid agreed to pay $50,000 to GridAmerica in exchange for the Class A units necessary for it to become an initial member. *Id.* at 19. In addition, National Grid has agreed to contribute $10 million to GridAmerica's startup costs but expects reimbursement from the Midwest ISO or the GridAmerica Participants. *Id.* Finally, GridAmerica has agreed to commit up to $500 million to purchase transmission assets for GridAmerica. *Id.* Mr. Venhuizen said that the Master Agreement contains a put right for the GridAmerica Companies that entitles these parties to sell their assets to GridAmerica at market price.

Mr. Venhuizen went on to discuss the Operation Agreement that governs the day-to-day relationship between GridAmerica and the GridAmerica Three. *Id.* at 20. The general structure of the entire GridAmerica transaction, according to Mr. Venhuizen, is that the GridAmerica Three will transfer functional control over their transmission facilities to GridAmerica that in turn will cede control to the Midwest ISO. Under the Operation Agreement, the GridAmerica Three will continue to be involved in the transmission system operation but only under the direction of GridAmerica and the Midwest ISO. He said that the GridAmerica Three, like other transmission owners in the Midwest ISO, will continue to perform many of the daily tasks involved in running a transmission system. However, the Midwest ISO and GridAmerica have the ability to direct the GridAmerica Three regarding these tasks. *Id.* at 20-21.

Mr. Venhuizen testified that Schedule 5A of the Operation Agreement contains a delineation of functions between GridAmerica and the GridAmerica Three, and makes it clear that GridAmerica retains control over transmission system functions but does describe the tasks to be performed and the input needed from the GridAmerica Three. *Id.* at 21. Mr. Venhuizen said GridAmerica will have control over all transmission facilities owned by the GridAmerica Three. In addition, the GridAmerica Three will enter into an agency agreement with GridAmerica that will permit GridAmerica access to non-transferred facilities that may be needed for wholesale service, such as network service. *Id.* at 21-22. The Operation Agreement provides that GridAmerica must operate the transferred transmission facilities in a non-discriminatory manner and accordance with good utility practice and all applicable National Electric Reliability Council ("NERC") requirements. *Id.* at 22. The initial term of the Operation Agreement is five years but the parties have the option to terminate their participation after three years. This provision, according to Mr. Venhuizen, has been revised due to the FERC's requirement that the GridAmerica Three remain members of the Midwest ISO for five years. According to Mr. Venhuizen, revenues received from the Midwest ISO for transmission service over GridAmerica facilities may be distributed directly to the GridAmerica Three or to GridAmerica for redistribution. *Id.* at 22-23.

Mr. O'Malley testified that NIPSCO, like all other transmission owners within the Midwest ISO, will pay its proportionate share of the Midwest ISO's administrative costs incurred as a result of its participation in GridAmerica and the Midwest ISO. O'Malley Direct at 2. Mr. O'Malley stated that NIPSCO proposes to defer these administrative costs and record them as regulatory asset by making a debit to the regulatory asset account FERC 182. By way of Late Filed Exhibit No 6, Mr. O'Malley testified that NIPSCO was not seeking carrying costs on the amount of regulatory assets booked by NIPSCO under its proposal.

Mr. O'Malley stated that these administrative costs are required to be paid by NIPSCO because the FERC has required each company to belong to a RTO. However, NIPSCO has proposed to defer these costs for accounting purposes to prevent an adverse financial impact on NIPSCO while its underlying basic electric rates remain frozen. *Id.* Mr. O'Malley stated that as a result of a stipulation and settlement agreement ("Settlement Agreement") in Cause No. 41746, (*Ind. Util. Reg. Comm'n, September 23, 2002*) beginning July 1, 2002, NIPSCO will begin crediting its electric ratepayers monthly bills an annual amount of approximately $55 million for a minimum term of 49 months. Moreover during this 49 month period, NIPSCO's basic electric rates are locked in and NIPSCO is precluded from proposing any changes to these rates. *Id.* at 3. He went on to explain that even at the end of the 49 month period, NIPSCO will continue crediting its electric customers monthly electric bills amounts totaling approximately $55 million annually until the Company's basic rates are changed. *Id.* Mr. O'Malley stated that NIPSCO was seeking Commission authorization to defer the Midwest ISO administrative costs for the period beginning with the first payment to Midwest ISO of the administrative adder expenses and continuing until the date on which NIPSCO ceases crediting electric customers' electric monthly bills. He concluded his testimony by stating that the Company's current estimate of the Midwest ISO administrative costs is approximately $3.5 million annually. *Id.* at 4.

Mr. Torgerson testified that the Midwest ISO is fully supportive of GridAmerica's ITC membership in the Midwest ISO. Mr. Torgerson stated that the Midwest ISO has been in the forefront of ITC formation within RTOs, through Appendix I to the Midwest ISO agreement that incorporates ITCs in its OATT. Torgerson Direct at 2-3. Mr. Torgerson indicated that currently at least 4 ITCs, including GridAmerica, are either operating or forming under the Midwest ISO and are treated in the same manner as transmission owners. *Id.* Each ITC has an individual Appendix I ITC agreement with the Midwest ISO that accounts for the varying organizational and operational structures of the ITCs. *Id.* He noted that GridAmerica is a fully independent ITC that would be managed by a subsidiary, National Grid. Mr. Torgerson testified that the functions to be performed by the Midwest ISO, GridAmerica and the GridAmerica Three, are set forth in Schedules 5 and 5A to the ITC Agreement. *Id.* According to Mr. Torgerson, the ITC Agreement provides that Midwest ISO will be the security coordinator throughout the GridAmerica footprint, and that FERC has conditionally approved the delineation of functions between Midwest ISO, GridAmerica and the GridAmerica Companies. *Id.* at 3-4.

Mr. Torgerson testified the Midwest ISO is committed to providing reliable transmission service throughout its footprint and that, with the assistance of National Grid, transmission service in the NIPSCO service territory will be reliable. *Id.* He said that GridAmerica will initially participate in the system planning process in the same way that a transmission owner participates in the process. The fact that GridAmerica is an ITC will not absolve the company of its obligation to engage in region-wide system planning. The Midwest ISO, and its independent market monitor, will perform all market monitoring duties in the GridAmerica footprint. *Id.* at 5.

B. Direct Testimony of Grid America. Mr. Halas stated that National Grid Transco plc is an international energy delivery business and represents the largest investor-owned utility in the United Kingdom where it owns and operates high voltage electric transmission networks in England and Wales. Halas Direct at 2. National Grid, a wholly owned indirect subsidiary of National Grid Transco plc, is one of the top ten electricity companies in the Unites States with the largest electricity transmission and distribution network in the New England/New York region. *Id.*

Mr. Halas explained GridAmerica Holdings, Inc., is a wholly owned subsidiary of National Grid and will serve as an independent managing member of the GridAmerica. He said that the specifics of the contractual relationships are defined in the Operating Agreement, the Master Agreement, and the LLC Agreement. *Id.* at 3.

Mr. Halas indicated that he believes that there are several benefits to an ITC structure, including: 1) a singular focus on the transmission business; 2) efficiencies and best operating practices; and, 3) independence from market participants. *Id* at 3. In discussing each of these benefits, Mr. Halas indicated that the ITC's singular focus on transmission will require it to actively respond to the needs of customers on the system through operational best practices and efficient asset management. Mr. Halas also indicated that benefits flow to consumers through greater availability, reliability and efficiency of the transmission system, and through the reduction of system congestion that could otherwise result in artificially high energy prices. Finally, he testified that independence from market participants should allow a well-run ITC to align itself with the interests of the consumer by developing and adhering to performance-based incentive structures which reward the ITC for efficient, effective asset and operational management. *Id.* at 3-4.

Mr. Halas said GridAmerica will be a for-profit transmission company that will focus on providing superior customer service and reliable transmission service to users of the transmission system. *Id.* at *4*. He said that GridAmerica will invest in top-rate management, operators and facilities, and seek approval for appropriate transmission pricing, to support the competitive electricity marketplace. *Id.* Along with near-term operational efficiency, Mr. Halas said GridAmerica will focus significantly on the mid-to-long-term planning of transmission infrastructure and will also serve as a vehicle to finance and manage necessary improvements. He testified that National Grid has committed to invest $500 million in the GridAmerica transmission system. *Id.*

Regarding the steps taken to implement GridAmerica, Mr. Halas testified that transmission system models have been built incorporating analysis tools; and operating procedures and protocols have been fully developed by and between the Midwest ISO including its stakeholders; GridAmerica's staff has been trained; and the development and testing of systems and interfaces between the control areas have been performed. *Id.* at 5-6. Mr. Halas said that the creation of efficient structures are critically important to the success of efforts to create a competitive regional electricity market, and noted that National Grid has significant experience and has had significant success in bringing the benefits of such markets to consumers. He cited as an example the United Kingdom where National Grid has reduced congestion costs by 77% with customers saving some $750 million. In addition, National Grid has reduced controllable operating costs by 61% reducing the real costs of transmission by over 40% while increasing transmission transfer capability by 44%. This efficiency was gained at the same time that reliability was maintained to the degree of less than one voltage and frequency incident per year outside the standard. *Id.* at 5.

C. Direct Testimony of the Indiana Office of Utility Consumer Counselor. Dr. Boerger testified that while the OUCC is happy to see NIPSCO seeking to join MISO, he believes that their decision to join as part of GridAmerica is questionable. Boerger Direct at 3. As a "profit entity" Dr. Boerger expressed concern that Grid America may have motives that may, or may not, coincide with the provisioning of reasonably adequate service and reasonable rates in Indiana. *Id* While he acknowledges that transferring control of transmission facilities to another for-profit entity will not necessarily lead to poor service quality or higher rates, he submits that GridAmerica has no obligation to serve retail customers in the State of Indiana. *Id.* Accordingly, the business decisions of GridAmerica may be made with less of a focus on service to Indiana retail customers.

Dr. Boerger believes that NIPSCO did not provide sufficient justification as to why it chose to join MISO as part of GridAmerica, and took exception to conclusions presented by Mr. Venhuizen that: GridAmerica offers the ability to attract capital necessary to upgrade the transmission system; and, GridAmerica's independence will provide a second layer of independence. *Id.* at 4. Dr. Boerger stated that he saw no evidence of NIPSCO's inability to attract capital necessary for improvements in its service territory. In addition, Dr. Boerger saw no evidence of concern regarding the independence of MISO that could lead to the inference that a second layer of independence is appropriate or necessary. In fact, he stated that the second layer could provide problems for the Commission in its ability to gather information from GridAmerica and that relying on the goodwill of GridAmerica to obtain needed information does not appear to be good public policy. *Id.* at 5.

In response to testimony presented by Mr. Halas, Dr. Boerger indicated that while the savings obtained by National Grid in the United Kingdom appear to be impressive, a separate analysis was not performed to demonstrate that similar savings would be possible in Indiana. *Id.* at 6. Dr. Boerger indicated that he is concerned that NIPSCO could seek to transfer its transmission assets to GridAmerica without seeking additional approval of the IURC. *Id.* Such a transfer of assets could have retail rate implications and the Commission should consider this issue carefully in proceedings devoted to those issues. Accordingly, Dr. Boerger stated that any approval in this cause that increases risk of an asset transfer without explicit Commission approval should be avoided, and that any Order issued in this Cause should include a provision to ensure that NIPSCO obtains approval from the Commission, prior to any such transfer. *Id.* at 7.

With respect to the Midwest ISO's agreement to reimburse the GridAmerica Companies up to $36.2 million, Dr. Boerger indicated that he believes that the Midwest ISO could simply pass these costs through and that the Schedule 10 administrative adder, as presented in this Cause, may be higher than it otherwise would be. *Id.* Dr. Boerger expressed concern such action by the MISO could create a situation whereby all utilities in the MISO would be required to pay the start-up costs of the failed Alliance RTO. *Id.* Dr. Boerger concluded his testimony by saying that the Commission should make clear it is not giving up its jurisdiction over subsequent transfers of control of transmission facilities. *Id.* at 8.

D. Direct Testimony Presented by the Testimonial Staff. Dr. Borum testified regarding the incentive payments that might be agreed to between GridAmerica and the GridAmerica Three pursuant to Section 4.3.2 of the Operating Agreement. Borum Direct at 16. Dr. Borum testified that be believes that any proposal that would affect FERC's tariffs would likely require FERC approval. However, he stated that NIPSCO, when asked whether it would seek IURC approval of any compensation arrangements, responded that while such approval was not currently contemplated, NIPSCO would seek any applicable IURC approvals prior to the implementation of an incentive program. *Id.* at 17. Dr. Borum recommended that the Commission should require NIPSCO to obtain approval prior to its participation of any incentive compensation mechanism that is negotiated between GridAmerica and NIPSCO. *Id.*

Dr. Borum also discussed the divestiture of transmission facilities to GridAmerica. *Id.* at 19-21. Dr. Borum recommended that IURC should require NIPSCO to obtain Commission approval before NIPSCO sells or transfers ownership of its transmission facility to any other entity. He also indicated that the Commission should require NIPSCO to obtain IURC approval before it transfers functional control of its transmission facilities to an RTO other than the Midwest ISO, or to an ITC other than GridAmerica. *Id.* According to Dr. Borum either of these scenarios would likely involve circumstances and contracts that would require the Indiana Commission to determine whether the transfer was in the public interest. *Id.*

In his testimony, Mr. Chandley discussed four broad topics. 1) What it means for a utility to join an RTO; 2) The specific regulatory issues that should be considered by the Commission with respect to NIPSCO's proposal to join MISO; 3) The issues that arise from NIPSCO's focus on joining GridAmerica; and, 4) Issues regarding coordination between Midwest ISO and the PJM Interconnection LLC ("PJM"). At the conclusion of his testimony, Mr. Chandley recommends that the Commission approve the transfer of operational control of NIPSCO's transmission facilities to the Midwest ISO and the integration of NIPSCO's facilities into the eventual Midwest ISO market.

Mr. Chandley testified that as NIPSCO has proposed to join the MISO through GridAmerica, the Commission should be vigilant as to how the split of functions evolves between the two entities. He believes that GridAmerica's focus on acquiring and performing various RTO functions is a cause for concern and should be closely watched by the Commission to insure that it does not result in barriers to the creation of a common market for the Midwest. He also concludes that while there may be operational issues associated with local utilities choosing to join PJM rather than Midwest ISO, and vice versa, in the long term these choices should become less important as both RTOs move toward a common market. While Mr. Chandley recommended that the Commission support proposed transfers of operational control of transmission assets to RTOs, he also urged the Commission to be aware of the benefits associated with RTO membership and associated participation in the energy markets. In his opinion, the interplay between market participation and regulation will require close attention by the Commission.

E. Rebuttal Testimony Presented by the Petitioner. In response to testimony presented by Dr. Borum, Mr. Venhuizen stated he could generally accept two of Dr. Borum's three suggested conditions. Venhuizen Rebuttal at 2. Mr. Venhuizen indicated that: 1) NIPSCO would seek further IURC approval prior to exercising its put right to sell its transmission assets to GridAmerica; and, 2) NIPSCO would seek Commission approval prior to joining an RTO other than the Midwest ISO, or an ITC other than GridAmerica. Mr. Venhuizen stated should NIPSCO decide to take either of these actions, NIPSCO would clearly abide by any IURC regulations or requirements that may apply at that time.[6] *Id.* However, Mr. Venhuizen testified that while he could not specifically agree with Dr. Borum's third condition that NIPSCO be required to obtain IURC approval prior to entering into any incentive compensation arrangements with the GridAmerica participants, he stated that NIPSCO never contemplated that any incentive compensation arrangements applicable to the GridAmerica transaction would have any impact on its retail ratepayers. Accordingly, Mr. Venhuizen indicated that NIPSCO would agree to hold harmless its retail ratepayers from any effects from the GridAmerica incentive compensation arrangement. *Id.* at 2-3.

In response to testimony presented by Dr. Boerger, Mr. Venhuizen indicated that the two conditions that Dr. Boerger recommends in his testimony are the same conditions that NIPSCO agreed to in response to testimony presented by Dr. Borum. However, Mr. Venhuizen also testified that he believes that Dr. Boerger's testimony is incorrect in a number of respects. Mr. Venhuizen stated that, as a condition of approving the RTO membership choices of all of the former Alliance Companies, the FERC issued an order which *required* that such membership be through an ITC managed by National Grid. *Id.* at 6. According to Mr. Venhuizen, NIPSCO is obligated to comply with FERC directives regarding RTO membership, and GridAmerica meets FERC's mandate that former Alliance Companies join an ITC managed by National Grid. *Id.* Also in response to Dr. Boerger's testimony, in which he specifically questioned the role that ITCs could play to enhance investment in the transmission sector and the need for a "double layer of independence", Mr. Venhuizen noted that FERC expressly identified enhanced investment potential and double independence as two important benefits of ITCs. *Id.* at 6-7.

Mr. Venhuizen stated that it appears from Dr. Boerger's testimony that the profit nature of ITCs has created additional concerns on the part of the OUCC. *Id.* at 7. According to Mr. Venhuizen, RTO membership insures that all load, including retail load, is served on an even basis. Mr. Venhuizen said there is also no basis for assuming that GridAmerica will be less forthcoming regarding information necessary for the Commission to assess NIPSCO's retail service and that NIPSCO commits to work with the Midwest ISO and GridAmerica to insure that the Commission has access to all necessary information. *Id.*

6. When questioned from the Bench on this issue Mr. Venhuizen indicated that, as he understands it, under current legal requirements it would be necessary for NIPSCO to seek and receive Commission approval in the event that the company chose to take either of these actions.

F. Rebuttal Testimony Presented by GridAmerica. In Mr. Halas' opinion, GridAmerica has a very real responsibility to all customers on the transmission system and a direct interest in assuring that the transmission system provides for the reliable and efficient transfer of energy in a cost-effective manner. Halas Rebuttal at 2. Mr. Halas believes that GridAmerica's interest is analogous to ensuring that a highway system is in good repair in order to provide efficient access throughout an area along with efficient access to local roads. *Id.* at 2.[7] Accordingly, Mr. Halas disagreed with Dr. Boerger's concern that, as GridAmerica does not have any obligation or responsibility to serve Indiana retail customers, lower service quality or higher rates could result.

Mr. Halas testified that one goal of National Grid is to expand the footprint of GridAmerica in order to provide a deeper level of operational services to its members. In response to the OUCC's concern as to whether similar savings can be created in the United States as those created in the United Kingdom, Mr. Halas stated that it is National Grid's intention to provide these benefits in the United States. *Id.* Mr. Halas testified that increasing the capability of the transmission system will lead to increased throughput on the system; increased reliability; and, increased access to broader markets. He said that the transmission system in the United States has not kept pace with growth in generation and the increasing demand for electricity. *Id.* at 3. Transmission bottlenecks threaten reliability and cost consumers hundreds of millions of dollars each year. *Id.* Mr. Halas noted that investment in new transmission facilities has declined steadily for the last 25 years. Mr. Halas submitted that with the right incentives, this aging transmission infrastructure can be updated and/or replaced with efficient and technologically advanced systems that can provide market benefits and reduce the negative impact of congestion as the market spreads. *Id.* at 3-4.

Mr. Halas disagreed with Dr. Boerger's statement that GridAmerica's second layer of independence poses potential problems in the areas of information access for the IURC. *Id.* at 4. He said that it is GridAmerica's intention to work cooperatively with regulatory entities, such as the IURC, and that it is not GridAmerica's intention to deny to the IURC any information to which it is currently entitled. Mr. Halas testified that GridAmerica expects to foster a good open relationship with the IURC within the bounds of good corporate governance. Mr. Halas said that GridAmerica has been very clear of its intent to be cooperative with entities having interests in its business, including the IURC, but it is not appropriate or concomitant with GridAmerica's fiduciary duties to waive legal rights that protect information from unnecessary disclosure in a way that compromises GridAmerica's operations, standards of conduct or other legitimate reasons for confidentiality. He stated that he expected most differences of opinion regarding information to be resolved informally. *Id.* at 5.

Mr. Halas disagreed with Mr. Chandley's statement that the current allocation of functions to GridAmerica may compromise the Midwest ISO's integrated regional dispatch. *Id.* at 6. He noted that an ITC's focus is on the transmission business, not on the operation of the market and its products. *Id.* at 8. The FERC has recognized the role that National Grid could perform in helping

7. Mr. Halas' Rebuttal testimony contains two (2) separate pages identified as "page 2." This citation references the 2[nd] page 2 of his testimony.

PJM and MISO bring their markets together. The functions that GridAmerica has undertaken under the current Midwest ISO structure, and those it will undertake when the Midwest ISO's market is implemented, will ensure efficient grid operations and expansion while independent market functions are performed by the RTO. *Id.* According to Mr. Halas, the role of the RTO under this arrangement will be to identify congestion in the marketplace and quantify its costs; it will be the objective of the independent transmission company to reduce the costs of that congestion, an objective that would perhaps not be shared by a market participant with other interests to consider. *Id.* at 9.

8. <u>Discussion and Commission Findings</u>. In undertaking this investigation the Commission sought to determine the *status* of NIPSCO's efforts to join an RTO, consistent with our past directives, and directives presented by the FERC. In response to our investigation, NIPSCO requested *approval* from this Commission to turn over "functional control," but not ownership, of its transmission system to the Midwest ISO, via ITC GridAmerica. The issue for us today is whether we should permit such a transfer based on the evidence presented.

In prior orders regarding the proposed transfer for functional control of transmission assets to RTOs, we applied the public interest standard of review and explained that in considering whether a transfer satisfies the public interest test of IC § 8-1-2-83, the Commission will consider reliability, financial viability, impact on competition, impact on efficiency and rates and access to information. *In re Joint Petition of Indiana Michigan Power*, Cause No. 42032 (*Ind. Util. Reg. Comm'n*, December 17, 2001), at 5; *Joint Petition of Hoosier Energy, et al*, Cause No. 42027 (*Ind. Util. Reg. Comm'n*, December 17, 2001), at 5-6.

While the goal of improved coordination and reliability of the transmission grid underlies the Commission's ongoing support of membership in RTOs, the Commission recognizes that NIPSCO's proposal, if approved, would add an additional layer between the utility and MISO. This structure presents unique issues that have not previously been presented to the Commission that could create issues that impact coordination and communication between GridAmerica and MISO. Accordingly, in conjunction with our overall public interest review, we will, as an initial matter, review the background of FERC standards and objectives regarding ITCs.

A. Role and Development of ITCs. The development of ITCs seemingly came about as an outgrowth of the FERC's efforts to ensure the development of regional RTOs in accordance with its determinations *In Re Regional Transmission Organizations*, December 20, 1999, 89, FERC ¶ 61,285 ("Order No. 2000"). While the formation and participation of ITCs in RTOs was not an initial focus of FERC in its effort to implement an effective framework for the formation of RTOs, the FERC subsequently recognized that a single ITC, participating in adjoining RTOs, could perhaps assist each of the individual RTOs in their efforts to address coordination and seams issues between the two entities.

In an Order issued on July 31, 2002, *In re Alliance Companies*, 100 FERC P61, 137 (2002) ("July 31, 2002 Order"), the FERC discussed the specific issue of ITC participation and the possible benefits that this arrangement could provide to PJM and MISO, in the event that National Grid served as an ITC for each entity. In this dual role, the FERC believed that National Grid could act as an overarching entity that could serve as a bridge between MISO and PJM in order to help manage, and mend, the seams between the two entities until a common market is developed. *Id.* at pp. 42, 43.

While the FERC anticipated that National Grid could act as a unifying force between the MISO and PJM, the FERC recognized that only the Midwest ISO had a tariff in place to allow for the formation and participation of ITC's within its structure. *Id.* at p. 43. PJM's tariff did not provide for the inclusion of ITCs, and the FERC expressed concern regarding the timely and appropriate development of the proposed delegation of functions within PJM and an ITC. *Id.* The FERC recognized that if the delegation of functions are not consistent as to MISO, PJM, and their respective ITCs, the ITCs ability to effectively mitigate seams between the two organizations could be compromised (and lead to additional seams) if the functions allocated to the ITC differ on either side of the seam. *Id.* In an effort to address these underlying issues, the FERC required PJM to revise its tariff to permit ITCs to operate under PJM as Midwest ISO does, and indicated that any ITC agreement with PJM must mirror the allocation of functions provided for in the April 2002 Order and the TRANSLink Order. *Id.* at pp. 43, 44.

While the Indiana Commission commends the FERC for its efforts to plant the seeds necessary for broad participation by National Grid as an ITC in the PJM and MISO, subsequent events have not resulted in the fruition of this approach. While the PJM has amended its tariff to allow for the participation of ITCs within its organizational structure, agreements have not been reached between PJM and ITCs under its purview. National Grid's proposed involvement as an ITC is currently limited to the participation of GridAmerica within MISO, without any corresponding involvement by National Grid in PJM. Under the present scenario, the role envisioned by FERC, of an ITC that would serve as an overarching entity that bridges two RTOs and helps PJM and MISO address seams issues, has not occurred. Rather than providing broad coordination of issues, the existence of an ITC, within a single RTO, could have the unanticipated impact of simply adding an additional layer of cost and bureaucracy to the existing RTO structure while providing none of the broader objectives initially visualized by the FERC.

Throughout his testimony in this Cause, Mr. Venhuizen indicates that NIPSCO had no choice but to pursue membership in an RTO through an ITC, as this approach has been mandated by the FERC. However, in response to questions from the Bench, Mr. Venhuizen was unable to direct the Presiding Officers to the specific FERC directive that (according to Mr. Venhuizen) made NIPSCO's proposal to join Grid America *mandatory*. Mr. Venhuizen's difficulty in providing a response to the Bench's request for clarification on this issue was perhaps due to the fact that there is no such mandate from the FERC. Contrary to the position presented by NIPSCO in this Cause, the FERC did not *require* NIPSCO, or any other entity, to pursue membership in an RTO under the auspices of an ITC. In fact, NIPSCO is the only Indiana utility that has proposed joining an RTO through an

ITC. Other utilities in the State have pursued, and been granted approval to transfer functional control of their transmission assets to RTOs, without the involvement of an ITC.

In light of this background of events before the FERC, regarding the role and development of ITCs within the RTO structure, we continue our public interest review in this Cause:

(i) Financial Viability and Access to Information. In Cause No. 42027 the Commission approved requests made by several Indiana electric utilities to transfer functional control of their transmission assets to the MISO. As part of our determinations made in that Cause, we concluded that the MISO had the requisite financial viability, and would provide access to information in a manner acceptable to the Commission. While we do not believe that it is necessary to revisit these issues with respect to MISO in this Cause, NIPSCO's proposal to join MISO through GridAmerica, rather than simply joining MISO independently, presents new issues regarding the financial viability of GridAmerica and its willingness to provide access to information to the Commission.

The evidence presented in this Cause demonstrates that National Grid Transco plc is one of the top ten electricity companies in the United States, with the largest electricity transmission and distribution network in the New York/New England region. Halas Direct Testimony at 2. According to the testimony presented in this Cause, National Grid has committed to invest up to $500 million in the GridAmerica system. *Id.* at 4. As noted by Mr. Venhuizen, FERC has identified increased access to capital markets a potential ITC benefit. Venhuizen Direct Testimony at 5. Based on the evidence presented in this Cause, the Commission is satisfied with the financial viability of GridAmerica.

While the Commission is satisfied with the financial viability of GridAmerica, we recognize that the placement of GridAmerica, as an ITC between MISO and NIPSO, could impact this Commission's efforts to obtain needed information. Dr. Boerger raised this very issue in his testimony and expressed the general concern that the Commission may find it more difficult to obtain information from National Grid than from NIPSCO. Boerger Direct Testimony at 5. In response to this concern, Mr. Halas indicated that it is GridAmerica's intention to work cooperatively with the IURC in order to provide access to information.

Despite assurances from GridAmerica that it will cooperate with any request by the Commission for information, the Commission recognizes that it is ultimately NIPSCO's responsibility, as a regulated utility in the State of Indiana, to ensure that it, or GridAmerica, provides all necessary information to the Commission. Therefore, notwithstanding concerns expressed in this Cause, based on our review of the evidence presented in this matter, and GridAmerica's willingness to cooperate fully with the Commission, and with NIPSCO, regarding access to information, we hereby find that this issue has been adequately addressed in this Cause.

(ii). ***Reliability.*** NIPSCO's proposal to join the Midwest ISO through GridAmerica is intended to improve the reliability of service. Testimony presented in this Cause demonstrates that National Grid, the managing member of GridAmerica, has substantial expertise related to transmission operations and has successfully operated a transmission-only company in the United Kingdom. In addition, the record demonstrates that, since it commenced operations, the Midwest ISO has provided reliable transmission service.

While the evidence presented in this Cause demonstrates that the Midwest ISO, National Grid and GridAmerica stand ready to provide reliable transmission service and have the financial and technical ability to play their respective roles effectively, the Commission believes that carrying out their respective duties, in a coordinated and efficient manner, will present the greatest hurdle that must be overcome by these companies. In light of the recent blackout in the United States, we believe that coordination and communication between entities that manage the transmission grid is of the utmost importance in ensuring prompt action in response to emergency events. While the Commission recognizes that such coordination can occur between an RTO and TO directly, without the need for involvement by an ITC, we also understand that a role for an ITC has been provided as an option by the FERC and that we therefore must work within this arrangement.

In reviewing the facts in this case the Commission is aware that the inclusion of GridAmerica, between NIPSCO and MISO, if done unadvisedly, could have an adverse impact on reliability. The inclusion of this "extra" entity in the process could, without careful coordination; result in complications with respect to communication in a time of crisis when time is of the essence. The parties' work to develop agreements in this Cause, and their recognition that MISO has primacy over the ITC GridAmerica, should help to mitigate any potential adverse impacts with respect to the overall reliability of the transmission grid. In addition, it is our expectation that, in order to protect the reliability of the transmission grid the role of GridAmerica will be very limited with respect to operations, the calculation of transmission capacity, planning, maintenance, scheduling, interconnections, and physical control. These limitations are particularly important in the State of Indiana, where the current configuration of the market, and the attendant interconnection issues associated with the configuration, present difficult issues that must be addressed by the MISO. Accordingly, decisions made by an ITC such as GridAmerica should be subject to the review and control of the MISO to ensure non-discriminatory treatment of all entities. In addition, consistent with FERC directives, an ITC (such as GridAmerica) should coordinate with the MISO in order to ensure that its actions are consistent with the MISO's congestion management protocols in order to ensure reliable and efficient commerce over the transmission grid.

Based on the evidence presented in this Cause, and the foregoing discussion of the issue, the Commission hereby finds that NIPSCO has appropriately addressed reliability issues in this matter.

(iii). Competition, Efficiency and Rates. The Indiana Commission has supported the FERC's efforts to develop a competitive wholesale market and to encourage transmission owning utilities to join RTOs. The Commission has previously approved applications of other Indiana utilities to join the Midwest ISO. As noted by Witness Chandley, "the State's first priority is to get its utilities into functioning RTOs." Chandley at 56. Despite witness Chandley's concern that GridAmerica may be involved in security-constrained economic dispatch when the Midwest ISO commences operations under so-called "Day 2" markets, Mr. Halas made clear in his rebuttal that GridAmerica will have no such involvement. Halas Rebuttal Testimony at 9 ("It is not GridAmerica's intent to perform security-constrained economic dispatch of the system on a regional basis."). Therefore, the Commission has the ability to act in a manner that will enhance competition in wholesale electric markets through its approval of RTO membership of another Indiana utility.

While Mr. Venhuizen testified that NIPSCO's application to join the Midwest ISO through GridAmerica will have no immediate impact on its retail rates in the State of Indiana, he did indicate that NIPSCO will be required to pay the Midwest ISO's Schedule 10 administrative adder to base zonal rates when GridAmerica begins operations. In presenting this issue in this Cause, Mr. Venhuizen indicated that NIPSCO would have to pay the Schedule 10 adder as a Midwest ISO member regardless of its participation in GridAmerica. Mr. O'Malley testifies that NIPSCO should be permitted to create a regulatory asset for the additional charges incurred by NIPSCO as a result of RTO membership. At this point, however, those costs will not be reflected in NIPSCO's retail rates.

In undertaking this investigation it was the Commission's intention to evaluate the status of NIPSCO's effort to join an RTO. Issues such as payment of the Schedule 10 adder and the creation of a regulatory asset for any additional charges incurred by NIPSCO as a result of RTO membership have not previously been included or addressed by the Commission in these types of proceedings. Instead, these issues have been addressed in separate proceedings initiated by utilities following Commission approval to transfer functional control of their transmission assets to an RTO.[8] Accordingly, we do not address these issues in this Cause, but hereby specifically condition our approval in this matter on NIPSCO's obligation to present these issues to the Commission, in a separately docketed and noticed proceeding, limited to consideration of these issues.

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8. *See*, Cause No. 42257, *Joint Petition of PSI Energy, Inc. and Vectren Energy Delivery of Indiana, Inc. Seeking Approval of Accounting Treatment With Respect to Certain Costs Incurred by the Joint Petitioners as a Result of Taking Transmission Service Under the Open Access Transmission Tariff of the Midwest Independent Transmission System Operator, Inc. to Service Their Respective Indiana Retail Electric Customers (Ind. Util. Reg. Comm'n, December 11, 2002)*; and, Cause No. 42266, Petition of Indianapolis Power & Light Company Seeking Approval of Accounting Treatment With Respect to Certain Costs Incurred by The Petitioner as a Result of Taking Transmission Service Under the Open Access Transmission Tariff of the Midwest Independent Transmission System Operator, Inc. to Serve its Indiana Retail Electric Customers *(Ind. Util. Reg. Comm'n, December 11, 2002).*

Therefore, based on the specific issues considered in this Cause, and the foregoing condition, we find that NIPSCO's proposed transfer of functional control of its transmission assets to MISO through GridAmerica, satisfies the issues addressed in this Cause.

9. Conclusion. The record in this case supports our determination that NIPSCO's decision to join the Midwest ISO through the GridAmerica ITC is consistent with options set forth by the FERC regarding membership in an RTO and could provide substantial benefits to Indiana ratepayers. Testimony presented in this Cause demonstrates that National Grid's experience in transmission-system operations should benefit GridAmerica and may enhance investment and innovation in the transmission sector. In addition, NIPSCO's membership in the Midwest ISO should benefit Indiana ratepayers by eliminating rate pancaking through the Midwest ISO footprint.

The Commission recognizes that the ITC arrangement proposed in this Cause is permitted by FERC and the MISO, however, the Commission believes that it is important to recognize that NIPSCO's decision to join MISO through an ITC creates potential issues, regarding coordination and communication and the possible long term impact on rates, due to the inclusion of Grid America. The Commission recognizes that FERC's vision for the development of ITCs within the overall RTO structure has not yet developed as planned. This fact alone lessens the potential benefits that ITCs could otherwise provide within the overall RTO structure. This fact, coupled with remaining issues regarding the need to develop effective coordination and communication between the two entities, leaves us to ponder why NIPSCO voluntarily chose to join MISO through an ITC rather than joining MISO directly in a manner consistent with what other utilities in the state have done.

Based on the entirety of the record presented in this Cause, and subject to the foregoing conditions set-forth in this Order, we find that the record in this Cause demonstrates that the transfer of functional control of NIPSCO's transmission facilities to GridAmerica and the Midwest ISO is in the public interest and should be approved. However, implicit in our decision issued today is the understanding that NIPSCO is also approved to transfer functional control of its transmission assets to the MISO directly, without the inclusion of Grid America.

10. Conditions. In addition to any conditions set forth previously in this Order, our approval in this Cause is hereby subject to the following additional conditions:

A. Future Transfers. Drs. Borum and Boerger both recommend that approval of the Petition be conditioned upon an obligation that NIPSCO seek IURC approval prior to joining an RTO other than the Midwest ISO or an ITC other than GridAmerica. In response, Mr. Venhuizen agreed that this should be addressed through a condition in the Order. In addition, as noted in Mr. Venhuizen's testimony, the GridAmerica Agreements contain provisions that allow NIPSCO to elect to transfer ownership of its transmission assets to GridAmerica through exercise of a "put" right. Venhuizen Direct Testimony at p. 19-20.[9] Drs. Borum and Boerger also recommend that approval of

9. Mr. Venhuizen indicated that in exchange for the transmission assets, NIPSCO will receive the fair market value of those assets in cash from GridAmerica and Class B units in GridAmerica.

the Petition be conditioned upon an obligation that NIPSCO seek IURC approval prior to exercising its put right in order to transfer ownership of its transmission assets to GridAmerica. In response, Mr. Venhuizen agreed. The record demonstrates, therefore, that approval of the Petition should also be conditioned upon NIPSCO obtaining approval from this Commission prior to transferring ownership of its transmission assets to any entity, or in the event that it elects to exercise the put right contained in the GridAmerica Agreements.

Accordingly, based on the Parties' agreement on this issue the Commission is approving NIPSCO's request to transfer functional control of its transmission assets to the Midwest ISO, through Grid America ITC. Consistent with the testimony presented in this Cause and assurances made to the FERC on this issue, this finding presumes that NIPSCO will remain a member of MISO for a period of five (5) years. The present application, and our approval thereof, would not be meaningful if NIPSCO, having transferred functional control to Grid America and the MISO pursuant to this Commission's authorization, could transfer this responsibility somewhere else without this Commission's approval. Therefore, consistent with our determination in Cause No. 42027, our approval in this Cause is conditional in that NIPSCO must seek Commission approval before it can transfer functional control of its transmission facilities to an RTO other than MISO; to an independent transmission company other than Grid America; or ownership of NIPSCO's transmission facilities to any other entity.[10]

B. Incentive Compensation. Dr. Borum recommended that NIPSCO be required to obtain Commission approval prior to implementing any plan for incentive compensation within GridAmerica. Dr. Borum indicated that such a condition is appropriate because incentive compensation arrangements may impact rates for retail service within NIPSCO's service territory. In response, Mr. Venhuizen stated that NIPSCO will "hold harmless" retail customers from the effects of any incentive compensation arrangements. Venhuizen Rebuttal Testimony at 2-3. In that manner, NIPSCO will assume any and all risks, and be entitled to any and all rewards, resulting from an incentive compensation plan applicable to the GridAmerica transaction.

The Commission hereby finds that NIPSCO's "hold harmless" proposal could, if properly and fully implemented, address incentive compensation mechanisms that are to be put in place between GridAmerica and NIPSCO. However, the Commission is aware that the transfer of

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10. By including this condition in this Order the Commission recognizes that jurisdiction over whether, when and how a company may depart from a FERC-jurisdictional arrangement lies with the FERC. But we do not view that jurisdiction as exclusive. IC § 8-1-2-83, applies to the subsequent transfers by our utilities no less than it applies to the initial transfer. It is true that the circumstances under which a member of an RTO may depart from the RTO are ruled by the RTO agreement, and that only FERC has jurisdiction over that agreement. From that statement, some may argue that FERC's jurisdiction over the departure is preemptive of the Commission's state law jurisdiction. We do not agree with this argument. The Commission believes that a reasonable protection of our jurisdiction, and respect for FERC's jurisdiction, is dependent upon the applicants' understanding that they must seek the Commission's approval before initiating or joining any filing at FERC in order to depart from MISO or Grid America, or to transfer functional control to any other RTO or ITC. *See*, Cause No. 42027, *Ind. Util. Reg. Commission*, December 17, 2001.

transmission assets to an RTO is intended to increase the overall efficiency of the transmission grid and lead to reduced costs for ratepayers. Therefore, NIPSCO's assurance that it will "hold its retail ratepayers harmless", from what may be a profit making venture created by the utility in an environment of decreasing costs, may not be sufficient to address issues regarding overall cost savings that should be passed on to the ratepayer on a going forward basis. Thus, while our Order in this Cause is hereby conditioned upon NIPSCO ensuring that its retail ratepayers in Indiana will not be adversely impacted by the incentive compensation plan adopted by the GridAmerica parties, it is also incumbent upon NIPSCO to continue to ensure that ratepayers fully realize any cost savings that result from RTO membership.

Accordingly, as a condition of this Order we hereby find that prior to implementing any incentive compensation arrangement with GridAmerica, NIPSCO must submit the arrangement to the Commission (under this Cause) in order for the Commission to ensure that the arrangement satisfies assurances made by NIPSCO that ratepayers will be held harmless, in a manner that also allows them to receive the full benefits from NIPSCO's membership in an RTO.

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

1. NIPSCO's request to join the Midwest ISO, either with the participation of GridAmerica ITC, or directly in its role as a Transmission Owner, is granted subject to the conditions set-forth in the body of this Order.

2. NIPSCO shall notify the Commission upon the transfer of functional control of its transmission system to MISO through GridAmerica.

3. This order shall be effective on and after the date of its approval.

McCARTY, LANDIS, RIPLEY AND ZIEGNER CONCUR; HADLEY ABSENT:
APPROVED: SEP 24 2003

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

Nancy E. Manley

Nancy E. Manley
Secretary to the Commission

ORIGINAL

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY ("NIPSCO") FOR (1) AUTHORITY TO MODIFY ITS RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE; (2) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES APPLICABLE THERETO; (3) APPROVAL OF REVISED DEPRECIATION ACCRUAL RATES; (4) INCLUSION IN ITS BASIC RATES AND CHARGES OF THE COSTS ASSOCIATED WITH CERTAIN PREVIOUSLY APPROVED QUALIFIED POLLUTION CONTROL PROPERTY PROJECTS; (5) AUTHORITY TO IMPLEMENT A RATE ADJUSTMENT MECHANISM PURSUANT TO IND. CODE § 8-1-2-42(a) TO (A) TIMELY RECOVER CHARGES AND CREDITS FROM REGIONAL TRANSMISSION ORGANIZATIONS AND NIPSCO'S TRANSMISSION REVENUE REQUIREMENTS; (B) TIMELY RECOVER NIPSCO'S PURCHASED POWER COSTS; AND (C) ALLOCATE NIPSCO'S OFF SYSTEM SALES REVENUES; (6) APPROVAL OF VARIOUS CHANGES TO NIPSCO'S ELECTRIC SERVICE TARIFF INCLUDING WITH RESPECT TO THE GENERAL RULES AND REGULATIONS, THE ENVIRONMENTAL COST RECOVERY MECHANISM AND THE ENVIRONMENTAL EXPENSE MECHANISM; (7) APPROVAL OF THE CLASSIFICATION OF NIPSCO'S FACILITIES AS TRANSMISSION OR DISTRIBUTION IN ACCORDANCE WITH THE FEDERAL ENERGY REGULATORY COMMISSION'S SEVEN-FACTOR TEST; AND (8) APPROVAL OF AN ALTERNATIVE REGULATORY PLAN PURSUANT TO IND. CODE § 8-1-2.5-1 *ET SEQ.* TO THE EXTENT SUCH RELIEF IS NECESSARY TO EFFECT THE RATEMAKING MECHANISMS PROPOSED BY NIPSCO.	CAUSE NO. 43526 APPROVED: AUG 25 2010

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

FINAL ORDER

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INTRODUCTION

On June 27, 2008, Northern Indiana Public Service Company ("Petitioner," "Company" or "NIPSCO") filed a Petition with the Indiana Utility Regulatory Commission ("Commission") for approval of (1) modifications to its rates and charges for electric utility service; (2) new schedules of rates and charges applicable thereto; (3) revised depreciation accrual rates; (4) inclusion in its basic rates of costs associated with certain previously-approved environmental projects; (5) a rate adjustment mechanism to timely reflect charges and revenues from regional transmission organizations ("RTOs"), purchased power costs, and off-system sales ("OSS") margins; (6) various changes to its electric service tariff; (7) the classification of its facilities as transmission or distribution in accordance with the Seven-Factor Test of the Federal Energy Regulatory Commission ("FERC"); and (8) an alternative regulatory plan pursuant to Ind. Code § 8-1-2.5-1 *et seq.* to the extent such relief is necessary to effect the ratemaking mechanisms proposed by NIPSCO.

Petitions to intervene were filed by NIPSCO Industrial Group ("IG"), Board of Commissioners of LaPorte County ("LaPorte"), City of Hammond ("Hammond"), City of Crown Point, Citizens Action Coalition of Indiana, Inc. ("CAC"), Indiana Municipal Utilities Group ("MU"), Beta Steel Corporation ("Beta Steel"), Newton County and the United Steelworkers. These petitions were granted, and these entities were made parties to this cause. The Indiana Office of Utility Consumer Counselor ("OUCC" or "Public") also participated in this proceeding as the statutory representative of the consumers.

Pursuant to the Prehearing Conference held on July 29, 2008 and the Prehearing Conference Order dated August 27, 2008, a procedural schedule was established for this proceeding.

The prepared testimony and exhibits constituting NIPSCO's case-in-chief were filed with the Commission on August 29, 2008 and NIPSCO's workpapers were submitted on September 5, 2008. Petitioner's case-in-chief was supplemented by the filing of an inadvertently omitted exhibit on September 5, 2008, a late-filed page and exhibit on September 8, 2008, corrections on September 29, 2008 and supplemental direct testimony concerning NIPSCO's customer notice on October 14, 2008.

On December 18, 2008, the parties filed with the Commission an agreed motion to continue the commencement of the initial evidentiary hearing by one week from January 6, 2009 to January 12, 2009. The motion stated that in accordance with a settlement agreement in Cause No. 43396 S1, a subdocket proceeding concerning NIPSCO's acquisition of the Sugar Creek Generating Station ("Sugar Creek"), and the agreement of the parties, NIPSCO would shortly file revised and supplemental testimony incorporating Sugar Creek into the evidence in this case and addressing a correction of an error in its case-in-chief. The motion stated a short continuance would provide the other parties sufficient time to review NIPSCO's supplemental filing and assist in the efficient and orderly presentation of evidence at the hearing. The Commission initially denied the motion, but after NIPSCO's supplemental filing on December 19, 2008 and a motion for reconsideration by the parties filed on December 22, 2008, the Commission by a docket entry dated December 24, 2008, continued the commencement of the hearing until January 12, 2009. Subsequently, NIPSCO filed additional corrections to its case-in-chief on December 31, 2008, January 6, 2009 and January 9, 2009, and submitted revised case-in-chief workpapers on December 31, 2008. NIPSCO filed supplemental direct testimony and submitted supplemental workpapers relating to the cost of service study on January 26, 2009.

Pursuant to the Prehearing Conference, the Prehearing Conference Order, notice of hearing given as provided by law, proof of which was incorporated into the record by reference and placed in the official files of the Commission, and the Commission's docket entry dated December 24, 2008, a public hearing in this Cause commenced on January 12, 2009 and continued through February 6, 2009, at which time NIPSCO presented its case-in-chief and its witnesses were made available for cross-examination and questions from the bench.

Pursuant to Ind. Code § 8-1-2-61(b), a public field hearing was held on March 3, 2009 in the City of Gary, the largest municipality in Petitioner's service area. At the field hearing, members of the public were afforded the opportunity to make statements on the record to the Commission.

On April 9, 2009, NIPSCO, Beta Steel, Hammond, CAC, MU, LaPorte, IG and the OUCC filed a Joint Motion for Extension of Time requesting an extension of the remaining prefiling and workpaper submission deadlines to allow the parties to analyze and file testimony in response to a corrected version of NIPSCO's cost of service study that was provided by NIPSCO on April 8, 2009, and for which NIPSCO would provided corrected rate design, revenue proof and tariff information on April 10, 2009. In the motion, NIPSCO agreed not to object to other parties making its corrected cost of service study an exhibit in their respective testimonial submissions. This Motion was granted by Docket Entry dated April 14, 2009.

On April 30, 2009, IG filed a Motion for Involuntary Dismissal pursuant to Trial Rule 41(B) contending that the Commission should disallow recovery of charges to NIPSCO for services provided by NiSource Corporate Services Company ("NCS"). NIPSCO filed a response to the motion on May 11, 2009, and the IG filed a reply to NIPSCO's response on May 18, 2009. By Docket Entry dated June 16, 2009, the Presiding Officers determined that the motion would be addressed in this Order.

On May 5, 2009, Beta Steel, MU, LaPorte, IG and the OUCC filed a Joint Submission of Consumer Parties' Joint Exhibits 1 and 2. Joint Exhibit 1 was a copy of the Third Revised Cost of Service Study provided by NIPSCO on April 8, 2009, including correspondence related thereto. Joint Exhibit 2 was a copy of revisions to the Third Revised Cost of Service Study, including correspondence related thereto, that was provided by NIPSCO to the parties on May 1, 2009, which included some additional changes.

On May 7, 2009, the OUCC filed written comments received from consumers since the March 3, 2009 field hearing. The OUCC filed additional consumer comments on August 4, 2009.

On May 8, 2009, the OUCC and Intervenors filed the prepared testimony and exhibits constituting their respective cases-in-chief. Supplements and corrections to IG's case-in-chief were filed on May 11, 2009 and June 23, 2009. LaPorte's case-in-chief was supplemented by the filing of revised testimony on July 17, 2009. On May 15, 2009, the OUCC and Intervenors filed their workpapers. The OUCC submitted corrections to its workpapers on May 22, 2009.

On May 29, 2009, the OUCC, IG and MU filed cross-answering testimony and exhibits responding to each other's prefiled evidence. IG submitted cross-answering workpapers on June 2, 2009.

On June 26, 2009, NIPSCO filed its rebuttal testimony and exhibits. NIPSCO's rebuttal testimony and exhibits were supplemented by the filing of inadvertently omitted and corrected exhibits on June 29, 2009 and July 14, 2009. NIPSCO's rebuttal workpapers were submitted on June 30, 2009 and supplemented on July 1, 2009.

On July 23, 2009, the OUCC filed its Objection and Motion to Strike Testimony of Intervenor's Witness Nicholas Phillips, Jr. IG filed a response to the OUCC's objection and motion on July 24, 2009. After a brief discussion on the record and clarification by IG as to the purpose of the testimony in question, the OUCC withdrew the objection and motion.

Also on July 23, 2009, NIPSCO filed a Motion for Limitation of Cross-Examination by Parties with Similar Interests and Supporting Memorandum. IG filed a response to NIPSCO's motion on July 24, 2009. At the evidentiary hearing, Beta Steel, LaPorte, CAC, MU and the OUCC joined in IG's response to NIPSCO's motion. After a brief discussion on the record, the Commission denied NIPSCO's motion but noted for the record that friendly cross-examination is not permitted.

Pursuant to a docket entry of the Commission dated May 4, 2009 and notice as provided by law, two additional field hearings were held on July 15, 2009 in the City of Michigan City at which time members of the public were afforded the opportunity to make oral and written statements on the record to the Commission.

On July 27, 2009, an evidentiary hearing was commenced at which time the cases-in-chief and cross-answering testimony of the OUCC and Intervenors and NIPSCO's rebuttal evidence were admitted and their witnesses were made available for cross-examination and questions from the bench.

Pursuant to a schedule agreed to at the final hearing, as modified subsequent to the hearing, NIPSCO filed its proposed order on October 15, 2009, the OUCC and Intervenors filed proposed orders and exceptions on December 4, 2009 and cross-answering briefs on December 30, 2009, and NIPSCO filed its reply brief on January 26, 2010.

Having considered the evidence and being duly advised, the Commission now finds:

1. <u>Notice and Jurisdiction</u>. Due, legal and timely notice of the filing of the Petition in this cause was given and published by Petitioner as required by law. Proper and timely notice was given by Petitioner to its customers summarizing the nature and extent of the proposed changes in its rates and charges for electric service. Due, legal and timely notices of the Prehearing Conference and the public hearings in this cause were given and published as required by law. Petitioner is a public utility as defined in Ind. Code § 8-1-2-1(a) and is subject to the jurisdiction of the Commission in the manner and to the extent provided by the laws of the State of Indiana. This Commission has jurisdiction over Petitioner and the subject matter of this proceeding.

2. **Petitioner's Characteristics.** Petitioner is a public utility with its principal place of business located at 801 East 86th Avenue, Merrillville, Indiana 46410. NIPSCO is authorized by the Commission to provide electric utility service to the public in all or part of Benton, Carroll, DeKalb, Elkhart, Fulton, Jasper, Kosciusko, LaGrange, Lake, LaPorte, Marshall, Newton, Noble, Porter, Pulaski, Saint Joseph, Starke, Steuben, Warren and White Counties in northern Indiana. NIPSCO also provides gas utility service in northern Indiana. NIPSCO is a wholly-owned subsidiary of NiSource Inc. ("NiSource").

3. **Existing Rates.** Petitioner's existing basic rates and charges for electric utility service (sometimes referred to herein as "base or basic rates") were established pursuant to the Commission's Order dated July 15, 1987 in Cause No. 38045 ("1987 Rate Order"). On September 23, 2002 in Cause No. 41746, the Commission approved a settlement agreement in a proceeding initiated by the Commission to investigate NIPSCO's electric rates ("Rate Investigation"). The settlement agreement provided that the terms of the 1987 Rate Order will remain unchanged as they relate to NIPSCO's basic electric rates and depreciation rates but, among other things, provided for customer bill credits of approximately $55 million per year until the Commission enters a basic rate order approving revisions to NIPSCO's basic electric rates.

4. **Test Year and Rate Base Cutoff.** As provided in the Prehearing Conference Order, the test year to be used for determining Petitioner's actual and pro forma operating revenues, expenses and operating income under present and proposed rates is the twelve months ended December 31, 2007. The financial data for this test year, when adjusted for fixed, known and measurable changes as provided in the Prehearing Conference Order, is a proper basis for fixing new rates for Petitioner and testing the effect thereof. The Prehearing Conference Order provided the general rate base cutoff shall reflect used and useful property at the end of the test year. On December 11, 2008, NIPSCO, the OUCC, IG and LaPorte filed a settlement agreement in Cause No. 43396-S1 that provided that Sugar Creek was accepted as an internal designated network resource of NIPSCO by Midwest Independent Transmission System Operator, Inc. ("Midwest ISO") effective December 1, 2008 and that the OUCC, IG and LaPorte would not challenge the inclusion of Sugar Creek in NIPSCO's rate base in this proceeding and the inclusion of reasonable expenses associated with Sugar Creek in NIPSCO's revenue requirement in this proceeding. Accordingly, Sugar Creek was included in NIPSCO's rate base and operating expenses for purposes of this proceeding.

5. **Relief Requested.** In its case-in-chief, NIPSCO proposed that its basic rates and charges be revised to produce annual revenue net of costs for fuel, purchased power and associated taxes ("gross margin" or "margin") of $962,393,192 plus non-trackable fuel expense of $11,669,787, for a total amount of $974,062,979. Miller Direct at 2-3. NIPSCO proposed to remove all of the cost of fuel traditionally recoverable through the fuel adjustment charge ("FAC") from base rates. *Id.* at 2. As discussed hereafter, the determination of the increase in NIPSCO's existing base rates depends upon the manner in which pro forma present rate revenues are adjusted to include or exclude fuel, the bill credits from the Rate Investigation settlement agreement and the discounts provided to certain industrial customers pursuant to Commission-approved customer specific contracts. Under NIPSCO's case-in-chief analysis, its proposed base rates would produce additional gross margin of $85,744,828. NIPSCO asserted its proposed base rates were intended to provide the opportunity to earn net operating income of

$223,095,808. *Id.* at 3. In its rebuttal presentation, NIPSCO reduced its proposed NOI level to $220,900,254. Miller Rebuttal at 7; Petitioner's Ex. LEM-R2, p. 2, l. 83, Col. J. NIPSCO also sought approval of revised depreciation accrual rates; a tracking mechanism for Midwest ISO revenues, Midwest ISO costs, purchased power, and Off System Sales ("OSS"); and reclassifications of transmission and distribution plant pursuant to the Seven-Factor Test.

6. Overview. Robert C. Skaggs, Jr., President and Chief Executive Officer of NiSource, provided an overview of NiSource and its corporate structure and explained NiSource's strategic direction. Mr. Skaggs explained that NiSource is a Fortune 500 company headquartered in Merrillville, Indiana, and is organized into three business units: (i) Northern Indiana Energy (which includes NIPSCO, Northern Indiana Fuel & Light Company and Kokomo Gas and Fuel Company), (ii) Gas Distribution, and (iii) Gas Transmission and Storage. Skaggs Direct at 3.

Mr. Skaggs stated that one of his initial priorities upon assuming his current responsibilities was to conduct a strategic review to identify corporate strengths and weaknesses and to define the future strategic direction of NiSource. Mr. Skaggs testified that one of the key findings from that review was that NiSource's core strengths were driven by its regulated infrastructure assets and that the ability to capitalize on those core strengths would require a long-term, investment-driven plan to modernize those core assets and core processes and raise the level of services they support. Skaggs Direct at 4.

Mr. Skaggs stated that, for NIPSCO's electric service, this includes significant increases in vegetation management, additional investments in generating stations and implementation of a contemporary work management system. Skaggs Direct at 6. Mr. Skaggs indicated that investment in NIPSCO's electric system will continue to increase due to environmental compliance, infrastructure growth, public improvements, capacity enhancements and infrastructure replacements. *Id.* In addition to assets and systems, Mr. Skaggs explained that NIPSCO also is addressing the fact that many of its experienced employees will reach retirement age over the next few years. He stated that new positions are being created to ensure NIPSCO has the skills and resources required to execute its business plans. *Id.* at 9. Mr. Skaggs cited NIPSCO's $330 million investment in Sugar Creek as an example of NIPSCO's effort to modernize its generating fleet and improve system reliability. Finally, Mr. Skaggs discussed the importance to NIPSCO and NiSource of credit ratings and the impact of regulatory treatment on those credit ratings. *Id.* at 10-11.

Eileen O'Neill Odum, Executive Vice President and Group Chief Executive Officer for NiSource's Indiana Business Segment and President of NIPSCO, described NIPSCO's mission and focus, provided an overview of its electric system and operations, and briefly summarized the relief requested by NIPSCO in its case-in-chief. Ms. Odum explained that NIPSCO's mission is to provide its customers with safe and reliable electric and gas service at just and reasonable prices. She said NIPSCO maintains a strong focus on all of its stakeholders including customers, employees, communities and regulators. Ms. Odum noted that NIPSCO has recently taken a number of important steps in support of its core mission, including the acquisition of Sugar Creek, a gas-fired combined cycle combustion turbine generating facility and its decision to retire the D.H. Mitchell Generating Station ("Mitchell") and Units 2 and 3 of the Michigan City Generating Station ("Michigan City Units 2 and 3"), which are NIPSCO's oldest coal-fired and retrofitted gas-fired generating facilities. She commented on NIPSCO's increase in security at its key substations, its improvements in customer service, its high quality customer contact center in Merrillville and the upgrading of its system infrastructure. Odum Direct at 2-4.

Ms. Odum also testified as to the recent reorganization of NIPSCO into the Northern Indiana business unit, which Ms. Odum stated provides clear accountability for all aspects of business performance and reinforces NIPSCO's focus on its customer segments. Ms. Odum explained that related to this reorganization was the establishment of 83 positions intended to further NIPSCO's focus on customer satisfaction, system reliability and regulatory transparency. Ms. Odum also highlighted NIPSCO's plan for additional hiring in order to deal with NIPSCO's aging workforce. Odum Direct at 4-5.

Ms. Odum stated that while industrial customers make up less than 1% of NIPSCO's 457,000 electric customers, they consumed more than 53% of the electricity sold during the test year. Odum Direct at 6-7. Ms. Odum also discussed NIPSCO's generation fleet and its plans to retire, demolish and remediate the Mitchell site and to retire and remove the equipment at Michigan City Units 2 and 3. *Id.* at 7-8. She explained that functional control of NIPSCO's transmission system now resides with Midwest ISO which operates under FERC authority as a non-discriminatory open access transmission provider. *Id.* at 7. Ms. Odum testified NIPSCO's generating units are dispatched by Midwest ISO on a security-constrained economic dispatch basis and NIPSCO participates in the Midwest ISO energy markets. *Id.*

Ms. Odum discussed steps NIPSCO has taken to manage escalating costs for operation and maintenance expenses through rigorous budgeting, competitive procurement practices and the implementation of a work management initiative. But she noted there are some costs over which NIPSCO has little control, such as environmental compliance and market prices for materials, equipment and contract labor. Odum Direct at 9-10.

Ms. Odum described the challenges facing NIPSCO in particular and the electric industry in general. Ms. Odum testified that planning for uncertain future changes in environmental regulation, principally carbon emissions, presents a very significant challenge for most electric utilities which, like NIPSCO, depend heavily on coal-fuel generators. Ms. Odum stated that escalating costs, including fuel, transportation and labor costs, pose a severe challenge to the ability of an electric utility to provide service at prices which recover its costs yet remain reasonable for customers. More specific to NIPSCO, Ms. Odum remarked on the substantial changes to NIPSCO's service territory and customer mix that have occurred in the twenty years since its last base rate case. Moreover, the transforming changes have taken place in the industry since then that require new rate mechanisms to deal with a new environment. Ms. Odum noted that NIPSCO's industrial customers represent the economic backbone of its service territory. These customers and their industries have undergone massive restructuring since NIPSCO's base rates were last set, resulting in a consolidation of the number and diversity of customers while the cost to serve them has increased. Ms. Odum testified that the relative cost of providing service has shifted among customer classes resulting in the need to "rebalance" NIPSCO's rate structure. Ms. Odum testified that NIPSCO's proposals in this proceeding represent a platform tailored to address these challenges. Odum Direct at 9-11.

Linda E. Miller, NIPSCO's Executive Director of Rates and Regulatory Finance, testified on NIPSCO's proposed revenue requirement. The adjustments reflected in her accounting exhibits were supported by a number of NIPSCO witnesses discussed in the consideration of the revenue requirement issues that follow.

Frank A. Shambo, NIPSCO's Vice President, Regulatory and Legislative Affairs, testified that when NIPSCO's current base rates were approved in 1987, the increase granted in that case was implemented in an across-the-board fashion. Given the passage of time and changes in circumstances, NIPSCO chose to substantially revise its tariff to reflect a complete assessment of ratemaking principles, cost of service and bill impacts. Shambo Direct at 3-4. Mr. Shambo stated one of the challenges in this proceeding is to balance equity between rate classes because this is the first time in over 20 years that NIPSCO's revenue allocation has been examined in detail. He noted that NIPSCO's industrial customers are subject to global competition and have options as to where they will produce their products. Mr. Shambo also acknowledged that NIPSCO was aware of challenges facing its residential customers. He asserted NIPSCO's proposed cost allocation and rate design takes into consideration the characteristics of all customer classes. *Id.* at 9-10. Mr. Shambo stated that in developing its proposals, NIPSCO considered differences between peak and off-peak usage, understandability, simplification, appropriate price signal and public policies supportive of economic development and energy efficiency. As a result of this review, NIPSCO proposed removing all fuel and purchased power costs from base rates and recovering all trackable fuel costs via the FAC; a Reliability Adjustment tracking mechanism; elimination of declining block rates; changes in its interruptible rates; a reduction in the number of customer rates; an economic development rider; and movement to cost-based rates tempered by gradualism. *Id.* at 9-25.

NIPSCO also presented witnesses on its proposed capital structure and cost of capital, depreciation accrual rates, cost of service study, rates, tariff revisions, tracking mechanisms, Seven-Factor Test reclassifications, and asset valuation.

7. **Petitioner's Rate Base.**

A. **Jurisdictional Used and Useful Property.** NIPSCO included in its rate base (a) property recorded as electric utility plant in service as of December 31, 2007 less Mitchell, Michigan City Units 2 and 3 and a portion of Unit 17 of the Schahfer Generating Station ("Schahfer 17") that was disallowed by the Commission's Order dated August 9, 1984 in Cause Nos. 37023-S1 and 37458; (b) Sugar Creek; and (c) an allocated share of common plant in service as of December 31, 2007, *i.e.* plant used in common for both electric and gas utility purposes. Miller Direct at 39-41; Petitioner's Ex. LEM-4 (Revised). Although there were issues regarding the valuation of NIPSCO's utility plant in service and the proportion of common plant to be allocated to the electric operation, there was no dispute about the used and useful nature of the utility property included by NIPSCO in its rate base. The Commission finds that such property is used and useful for the convenience of the public in NIPSCO's provision of utility service. Therefore, such property is includible in NIPSCO's rate base.

Mr. Shambo testified that in the test year NIPSCO provided small amounts of FERC-regulated wholesale service to the City of Argos, ancillary services to Indiana Municipal Power Agency and transmission service to Wabash Valley Power Association, Inc. Shambo Direct at 23. Mr. Shambo stated that due to the small size and incidental amount of this business, NIPSCO believes its electric business should be treated as 100% jurisdictional for ratemaking purposes and that revenues from these incidental services should be credited to retail customers. *Id.* No party opposed this proposal and the Commission finds it to be reasonable. Therefore, we shall treat NIPSCO's electric utility operations as 100% jurisdictional, credit the revenues from these incidental services to retail customers and treat the revenues as jurisdictional for purposes of the FAC earnings test. This is consistent with our treatment of Southern Indiana Gas and

Electric Company d/b/a Vectren Energy Delivery of Indiana, Inc. ("Vectren South") in our Order in Cause No. 43111 dated August 15, 2007 ("Vectren South Order"). See Vectren South Order, p. 6.

B. **Original Cost Rate Base.** In its case-in-chief, NIPSCO quantified its original cost rate base to be approximately $2.665 billion. Petitioner's Ex. LEM-4 (Revised). The OUCC proposed an original cost rate base of about $2.639 billion. Public's Ex. 2, Sch. TSC-2, p. 2. The only issues regarding NIPSCO's original cost rate base concerned common plant, deferred costs of the Pure Air project, a prepaid pension asset and cash working capital.

(1) Common Plant. Some of NIPSCO's utility plant is used in common for both electric and gas utility service. For purposes of determining NIPSCO's electric rate base, NIPSCO allocated the common plant to its electric operation using common cost allocation ratios described in the direct testimony of Mitchell E. Hershberger, NIPSCO's Controller. Hershberger Direct at 7-10. IG Witness Greg Meyer, a principal in the Brubaker & Associates consulting firm, disputed the appropriateness of NIPSCO's method of allocating NCS charges and internal common costs between NIPSCO's electric and gas operations. Mr. Meyer contended the amount of common plant allocated to electric should be reduced by $25 million based on a PowerPoint document produced by NIPSCO in discovery. Meyer Direct at 44, lines 11-12. This document is dated December 18, 2006 and is based on data from 2005, not the test year. IG Ex. CX-26, pp. 1, 28.

We will discuss Mr. Meyer's position on allocation ratios in detail in connection with our findings on the level of NCS charges to be included in NIPSCO's revenue requirement. Based on our conclusions with respect to allocation ratios, however, we reject Mr. Meyer's proposed $25 million reduction in the amount of common plant included in NIPSCO's electric rate base. In addition, we find Mr. Meyer's recommendation should be given little weight because IG's witnesses themselves could not agree on which original cost rate base to use. For instance, IG Witness Michael Gorman, another Brubaker & Associates consultant, used NIPSCO's proposed original cost rate base of $2,665,421,829 in determining the impact of his cost of capital recommendation on NIPSCO's revenue requirement. IG Ex. MPG-1, p. 1, l. 17 and p. 2, l. 25.

(2) Pure Air Deferred Asset. In its case-in-chief, NIPSCO included in its original cost rate base the unamortized balance at December 31, 2007 of deferred charges relating to the Pure Air flue gas desulfurization system at the Bailly Generation Station. Petitioner's Ex. LEM-4 (Revised), p. 1, l. 11. This deferral was authorized by the Commission in Cause No. 38849-S1. OUCC Witness Thomas S. Catlin, a principal with the Exeter Associates consulting firm, testified the Pure Air project deferred charges should be excluded from rate base because the amortization expired before the end of 2008. Catlin Direct at 7. For this reason, Mr. Catlin stated, NIPSCO Witness Linda E. Miller removed the test year Pure Air amortization expense from NIPSCO's adjusted operating expenses. *Id.* In her rebuttal testimony, Ms. Miller testified that NIPSCO did not object to removal of the Pure Air deferred asset from NIPSCO's rate base. Miller Rebuttal at 53. Therefore, we accept Mr. Catlin's recommendation and find the Pure Air deferred charge asset of $526,218 should not be included in NIPSCO's rate base.

(3) Prepaid Pension Asset. In its case-in-chief, NIPSCO included in its rate base a prepaid pension asset of $25,705,004. Petitioner's Ex. LEM-4 (Revised), p. 1, l. 15. At the hearing on NIPSCO's case-in-chief, Ms. Miller stated that there was a prepaid

pension asset at the end of the test year because the market value of the pension assets was increasing at that time. Tr. at P-55-P-56. However, due to changing market conditions, by December 31, 2008, the prepaid pension asset was down to zero and pension expense was up by tens of millions of dollars. Tr. at P-56. Ms. Miller stated the reduction in the asset value and the increase in the expense were inter-related. *Id.* Ms. Miller sponsored an updated calculation of NIPSCO's pension expense adjustment that reflected a significant increase in NIPSCO's pension expense due to post-test year changes in market conditions. Petitioner's Redirect Ex. 2.

OUCC Witness Catlin recommended that the prepaid pension asset be removed from rate base because it was eliminated in 2008 due to unfavorable market performance. Catlin Direct at 6. Mr. Catlin further testified that the asset does not represent money contributed by NIPSCO to the pension trust in excess of the amount collected from ratepayers, but rather is a calculation made by the plan actuary. *Id.* Mr. Catlin opined that the prepaid pension asset does not constitute investor-supplied capital upon which NIPSCO is entitled to earn a return. *Id.* at 7.

IG Witness Gorman also recommended that NIPSCO's prepaid pension asset be removed from rate base. Gorman Direct at 12. Mr. Gorman asserted that NIPSCO would earn a return on this asset twice if it is included in rates, first by receiving an investment return in the pension trust fund and then a second time from retail customers if the prepaid pension asset is included in the development of retail rates. *Id.* at 89. Mr. Gorman stated that the increased value of the pension asset does not represent the direct investment by NIPSCO that has not been recovered from customers, but rather reflects investment growth of previous cash contributions. *Id.*

In rebuttal, NIPSCO Witness Miller testified that NIPSCO is not opposed to the removal of the prepaid pension asset from rate base, provided that the Commission also reflects the corresponding increase in pension expense. Miller Rebuttal at 51. Ms. Miller stated that the prepaid pension asset on NIPSCO's balance sheet at December 31, 2007 was calculated based on a favorable return on pension plan assets during the test year and that the resulting asset was directly related to the pension credit expense amount reflected in the test year. *Id.* Ms. Miller further stated that at December 31, 2008, the next plan measurement date, unfavorable plan performance in 2008 resulted in elimination of the pension asset and the establishment of increased pension expense to be accrued during 2009. *Id.* She said pension expense accrual amounts are established for the coming year as of the measurement date used for the pension plan valuation. *Id.* Ms. Miller updated NIPSCO's pension expense adjustment to include the new pension expense accrual amount determined as of December 31, 2008. *Id.* at 52; Petitioner's Ex. LEM-R3, Adj. OM-3.

We will discuss the pension expense adjustment *infra*. With respect to NIPSCO's request to include the prepaid pension asset in rate base, the only evidence in Petitioner's case-in-chief purporting to support the inclusion is Ms. Miller's accounting exhibit showing the amount of the prepaid pension asset. A prepaid pension asset could be a voluntary payment by shareholders to supplement the required pension expenses. NIPSCO has presented no justification for including the prepaid pension asset in rate base, and without additional supporting evidence, we decline to include it in NIPSCO's rate base.

(4) Cash Working Capital. IG Witness Meyer testified that because NIPSCO's proposed rate base does not include any amount for cash working capital, NIPSCO is in essence requesting a zero working capital allowance. Meyer Direct at 44. Until last year, Mr. Meyer was employed by the Missouri Public Service Commission. Meyer Direct, Appendix A.

Based on his experience in Missouri, Mr. Meyer believed electric utilities generally have a negative working capital allowance and that a study performed for NIPSCO would likely show the same result. *Id.* Mr. Meyer based his opinion on summaries of lead lag studies performed by the Missouri Commission staff that related to AmerenUE and Kansas City Power & Light Company. IG Ex. GRM-11. Mr. Meyer noted that NIPSCO sells its accounts receivable to a third party, which accelerates the amount of time that NIPSCO receives cash from bills rendered to customers. *Id.* at 44-45. Mr. Meyer did not perform a lead lag study of NIPSCO but instead recommended that the Commission require NIPSCO to perform a lead lag study for inclusion in its next rate case. *Id.* at 47.

In rebuttal, NIPSCO Witness Miller testified that NIPSCO disagreed with Mr. Meyer's contention and it would be premature to ask the Commission to decide in this current rate case what should be done in a future rate case. Miller Rebuttal at 55-56. Further, Ms. Miller stated that Mr. Meyer provided no evidence to indicate that lead lag studies are required in rate cases or that NIPSCO's case is deficient because it does not contain one. *Id.* at 56.

No other major Indiana electric utility submitted a lead lag study in its most recent rate cases. *Ind. Michigan Power Co.*, Cause No. 43306 (March 4, 2009); *S. In Ind. Gas and Elec. Co.*, Cause No. 43111 (Aug. 15, 2007); *PSI Energy, Inc.*, Cause No. 42359 (May 18, 2004). Nor have we ordered those companies to do so in their next rate cases. IG has submitted no evidence explaining why NIPSCO should be treated differently than these other utilities. In comparison, our rules on Minimum Standard Filing Requirements state such studies need be submitted only if the utility is requesting an allowance for cash working capital, which is not the case here. 170 IAC 1-5-12(1). Accordingly, we reject Mr. Meyer's assertion that a lead lag study was required in this Cause.

(5) Quantification of Original Cost Rate Base. Based on the evidence and the findings made above, the Commission determines that the original cost of NIPSCO's property used and useful in the provision of electric utility service is as follows:

Description	Amount
Utility Plant	$ 5,205,578,748
Common Plant Allocated	214,502,540
Less Schahfer 17 Disallowed Plant	(31,733,655)
Total Utility Plant	5,388,347,633
Accumulated Dep. and Amort.	(2,800,380,478)
Sugar Creek Acc. Dep. and Amort.	(5,618,432)
Common Plant Acc. Dep. Allocated	(98,409,168)
Less Disallowed Plant Acc. Dep.	27,399,652
Total Accumulated Dep. and Amort.	(2,877,008,426)
Net Utility Plant	2,511,339,207
Schahfer 17 Deferred Dep. (CN 37129)	542,928
Schahfer 18 Deferred Dep. (CN 37819)	5,206,694
Schahfer 18 Def. Carrying Charges (CN 37819)	16,132,193
Prepaid Pension Asset	$0
Materials & Supplies	46,907,735
Sugar Creek Materials & Supplies	1,495,291
Production Fuel	57,566,559
Total Rate Base	$ 2,639,190,607

Sugar Creek has been included in the original cost rate base at the acquisition cost of approximately $328 million as identified in Ms. Miller's testimony. Miller Direct at 41. Accumulated depreciation and amortization has been increased for depreciation on Sugar Creek from June 1, 2008 through November 30, 2008, the period from its acquisition by NIPSCO through the period before it was a designated network resource in Midwest ISO. *Id.* No parties disagreed with NIPSCO's proposed treatment of the Sugar Creek amounts.

C. Fair Value of Rate Base.

(1) Legal Requirements. Ind. Code § 8-1-2-6 provides the Commission "shall value all property of every public utility actually used and useful for the convenience of the public at its fair value, giving such consideration as it deems appropriate in

each case to all bases of valuation which may be presented or which the commission is authorized to consider by the following provisions of this section." The Indiana Supreme Court has held use of fair value reflects not only legislative policy, but also a requirement of the Indiana Constitution. *Pub. Serv. Comm'n of Ind. v. City of Indianapolis*, 235 Ind. 70, 92-93, 131 N.E.2d 308, 317 (Ind. 1956). In determining fair value, the Commission cannot ignore the "commonly known and recognized fact of inflation." *Indianapolis Water Co. v. Pub. Serv. Comm'n of Ind.*, 484 N.E.2d 635, 640 (Ind. Ct. App. 1985). For this reason, "'reproduction cost new less depreciation cannot be disregarded in fixing a valuation for rate making purposes.'" *Id.* (quoting from *Pub. Serv. Comm'n of Ind. v. City of Indianapolis*, 235 Ind. at 108, 131 N.E.2d at 325).

(2) Evidence. In addition to its evidence on the original cost, NIPSCO submitted evidence on the fair value of its property using alternative ways of computing fair value. NIPSCO Witness John P. Kelly, an asset valuation specialist with Concentric Energy Advisors, Inc., determined the value of NIPSCO's electric properties including common plant allocated to the electric operation and excluding Mitchell, Michigan City Units 2 and 3 and Sugar Creek. In his valuation, Mr. Kelly used the replacement cost less depreciation ("RCNLD") approach. Kelly Direct at 3. To the extent the assets would be constructed today in substantially the same form, Mr. Kelly determined the cost to reproduce the property as it exists today. *Id.* at 8. Where assets would be replaced in a different form, he derived the cost for the functionally-equivalent assets that would be constructed today. *Id.* at 8-9.

To determine the reproduction cost of NIPSCO's property, Mr. Kelly applied cost trend factors to the original costs by vintage for each plant account. The trend factors were developed from the Handy-Whitman Index of Public Utility Construction Costs and other indices. Kelly Direct at 9, 12-15. He then made a downward adjustment to reflect loss in service value due to age and condition of property. *Id.* at 9. As part of this adjustment, Mr. Kelly also considered which assets would be replaced today with functionally-equivalent but different assets. *Id.* For production plant, Mr. Kelly used the cost of a new scrubbed coal facility as the replacement for NIPSCO's existing base load and intermediate load units and a new combustion turbine as the replacement for NIPSCO's hydroelectric and peaking units. *Id.* at 19. The construction and operating and maintenance ("O&M") costs of the alternative facilities were used to determine the physical and functional depreciation of the existing generating facilities. *Id.* at 17-18. For transmission, distribution and general plant, Mr. Kelly determined depreciation by reflecting the average service life, estimated remaining useful life and condition percent for each account. The condition percent was derived from the well-accepted Robley Winfrey tables published by Iowa State University. *Id.* at 20-21, 23. These steps resulted in a RCNLD value of $6,864,797,377. *Id.* at 25.

Mr. Kelly then made an additional adjustment to reflect economic depreciation applicable to the production plant. The economic depreciation amount reflected the results of a valuation of NIPSCO's generation facilities using the discounted cash flow ("DCF") method performed by NIPSCO Witness John J. Reed. Kelly Direct at 25-26. Mr. Reed, Chairman and Chief Executive Officer of Concentric Energy Advisors, Inc., determined the value of the generating assets (excluding Mitchell, Michigan City 2 and 3, and Sugar Creek) by discounting to present value the projected after-tax operating cash flows that would be generated during their remaining useful lives. Reed Direct at 7. Mr. Reed's analysis utilized energy price forecasts for each plant that were developed by Ventyx, a leading provider of electricity modeling services, using a detailed production cost model. *Id.* at 9. Mr. Reed stated this method determines the fair market value of the assets in a free, competitive market which is now possible because of the existence of competitive wholesale power markets. *Id.* at 12-13.

Mr. Reed's analysis also considered forecasted fixed and variable costs based on unit-specific heat rates, fuel costs, emission rates, forecasted capital expenditures (including for emissions reduction technology) and demolition costs. *Id.* at 8, 13, 17, 19. Mr. Reed developed a DCF value for the generation assets of $2.270 billion, an average of $819 per kW. *Id.* at 22. Mr. Kelly reflected the difference between his production plant RCNLD values and Mr. Reed's DCF production plant values as economic depreciation. Kelly Direct at 26-27. The resulting RCNLD value for the entire system, including production plant economic depreciation, is $6.33 billion. *Id.* at 27.

Paul R. Moul, Managing Consultant of the P. Moul & Associates consulting firm, also testified on the fair value of NIPSCO's property. Mr. Moul developed a fair value estimate that considered both the original cost less depreciation and replacement cost less depreciation of NIPSCO's property. Moul Direct at 43. Mr. Moul gave 49.94% weight to replacement cost and 50.05% weight to original cost. These are the ratios of the common equity and non-common equity components of NIPSCO's rate setting capital structure. Mr. Moul stated this method is a compromise approach that is intended to make sure that, at a minimum, the Company gets the benefit of the appreciation in value of its assets to the extent they were financed by the common equity investor. *Id.* For the replacement cost, Mr. Moul used Mr. Kelly's RCNLD value adjusted for economic depreciation to which he added Sugar Creek, deferred charges includible in rate base, the pension plan asset, materials and supplies and production fuel as shown on Petitioner's Exhibit LEM-4, p. 1. *Id.* at 43-44. For the original cost value, Mr. Moul used the original cost rate base as computed on the same exhibit. The result of Mr. Moul's weighting approach was a fair value of $4,733,099,690. *Id.* at 44.

LaPorte Witness Reed W. Cearley raised two specific issues regarding Mr. Kelly's RCNLD valuation. Mr. Cearley is an independent contractor retained by LaPorte as a special utility consultant in this proceeding. Cearley Direct at 1.

Mr. Cearley testified that Mr. Kelly's valuation improperly included $26,431,540 for "Intangible Plant" in his electric plant valuation and $63,185,925 for "Miscellaneous Intangible Plant" in his allocated common plant valuation, citing the part of Mr. Kelly's exhibits that included amounts recorded in Accounts 302 and 303 of the FERC Uniform System of Accounts ("USOA"). Mr. Cearley testified that Ind. Code § 8-1-2-6(b) provides all public utility valuations shall be based upon tangible property. Mr. Cearley therefore recommended that Mr. Kelly's valuation be reduced by $89,617,465 to eliminate intangible property from his valuation. Cearley Direct at 15-16.

Mr. Cearley also expressed his concern that the value of NIPSCO's property for ratemaking purposes and for tax purposes is not consistent. Cearley Direct at 16. Mr. Cearley maintained that, pursuant to Ind. Code § 8-1-2-6(a), the assessed value of NIPSCO's property was relevant to the Commission's determination of the fair value of that property for ratemaking purposes. *Id.* at 17. Mr. Cearley testified that the valuation of NIPSCO's property for tax purposes is significantly less than its valuation for ratemaking purposes and that Mr. Kelly improperly valued NIPSCO's real estate at a greater amount than the assessed value of its land exclusive of improvements valued for taxation. *Id.* at 18. Mr. Cearley concluded that the

Commission should consider the assessed value of NIPSCO's property in determining the fair value of NIPSCO's electric plant in service in this case. *Id.* at 19.

In rebuttal, NIPSCO Witness Miller responded that the intangible assets to which Mr. Cearley referred are software assets. Miller Rebuttal at 55. Ms. Miller said that these assets are properly included in the valuation because they are part of the cost of bringing NIPSCO's property to its present state of efficiency. Ms. Miller stated that she unaware of any Commission orders that have excluded software assets from rate base. *Id.*

(3) Fair Value Determination. NIPSCO presented its RCNLD evidence to support its proposed fair value of NIPSCO's utility plant, and with the exception of Mr. Cearley, no evidence was submitted challenging Petitioner's RCNLD study or its fair valuation methodology. However, as Ms. Odom confirmed on the first day of the hearing, NIPSCO was not seeking a revenue requirement based on fair value, but on original cost. Indeed, NIPSCO's evidence and proposed order presented in this Cause contain its net operating income request based on the original cost of NIPSCO's rate base. Further, NIPSCO did not present evidence of an inflation-adjusted fair rate of return to apply to its proposed fair value, but provided its cost of equity evidence in support of a return on its original cost rate base. While NIPSCO did calculate a fair return in its proposed order, its recommended return was merely used as a comparison to fair returns the Commission found for other electric IOUs. However, as NIPSCO failed to provide any evidence concerning an inflation adjustment to its cost of equity evidence, we find this comparison inappropriate and unnecessary.

The Commission is cognizant of its obligation to make a fair value determination under Indiana Code Section 8-1-2-6. However, it is unclear what purpose a fair value determination has in this Cause given NIPSCO's use of original cost in determining its NOI. The Commission does not engage in such decision-making for academic pursuits, and we do not do so here. A fair value determination is the first step to making the ultimate determination of a fair return using a fair rate of return. If the evidence is insufficient to support a subsequent step of the fair value calculation, the Commission need not proceed with any step of the calculation, and must use the evidence available to determine an appropriate revenue requirement.

Accordingly, although we find that NIPSCO presented evidence that the fair value of NIPSCO's utility property used and useful and in the provision of electric utility service is $4,707,000,000, we give no weight to this valuation in this Cause for purposes of calculating NIPSCO's revenue requirement. We must reach this conclusion given NIPSCO's failure to present evidence concerning the inflation-adjusted fair rate of return to apply to its fair value. Instead, as requested by Petitioner, we use Petitioner's original cost valuation for purposes of ratemaking in this proceeding.

8. Rate of Return.

A. Capital Structure.

(1) Evidence. NIPSCO determined its proposed cost of capital using its actual capital structure as of December 31, 2007 adjusted to (a) exclude $1,168,208 of equity representing accumulated Other Comprehensive Income ("OCI") relating to derivative activity; (b) include $160 million of additional long-term debt issued in June 2008; (c) exclude $795,992 of deferred taxes related to the OCI adjustment; and (d) exclude $10,040,730 of cost free capital

relating to post-retirement benefits other than pensions ("OPEBs") to correct for the erroneous inclusion in medical benefits expense of an amount that should have been reflected as a reduction in the OPEBs accrued liability. Miller Direct at 47-48; Petitioner's Ex. LEM-5 (2nd Revised), p. 2. The OCI adjustment was supported by Mr. Moul who agreed that amount should be removed because it represents cash flow hedges that have no impact on NIPSCO's rate base. Moul Direct at 13-14.

Tyler E. Bolinger, the Director of the OUCC's Electric Division, testified that NIPSCO has a strong balance sheet including an equity ratio of over 60% of its investor-provided capital which compares to an average of 43.5% for the Standard & Poor's ("S&P") utility group. Bolinger Direct at 11-12. He said NiSource, on the other hand, is "a highly leveraged firm facing major challenges attributable to its heavy reliance on debt" and "face[s] significantly higher debt costs relative to similar firms with stronger credit ratings and stronger balance sheets (i.e. lower debt ratios and higher equity ratios)." *Id.* at 11. Mr. Bolinger contended that NIPSCO is burdened by NiSource's weak balance sheet and credit ratings despite NIPSCO's stronger stand-alone profile. *Id.* at 12-13. Mr. Bolinger noted that NIPSCO gets its equity capital and some of its debt capital from NiSource. *Id.* He said NIPSCO's 60% equity ratio impacts NIPSCO's revenue requirement because the cost of equity is higher than the cost of debt. *Id.* at 13. Mr. Bolinger opined that it would be unreasonable and not in the public interest to use NIPSCO's actual capital structure in determining its cost of capital because ratepayers will pay the cost of NIPSCO's strong balance sheet and the cost of NiSource's weak balance sheet. *Id.* at 17. Mr. Bolinger concluded that OUCC Witness J. Randall Woolridge would sponsor a proposal to use a different capital structure. *Id.*

OUCC Witness Woolridge testified that NIPSCO's capital structure, consisting of 60.60% common equity and 39.40% long-term debt, was not appropriate for NIPSCO because it "is significantly out of line with the capital structures of electric utility companies" as represented by the average 2008 common equity ratio of his proxy group which is 46.7%. Woolridge Direct at 16-17. Dr. Woolridge further contended that NiSource's equity and debt ratios "are in-line with those of other electric utilities." *Id.* at 17. Dr. Woolridge proposed that for ratemaking purposes the equity and debt in NIPSCO's capital structure should be adjusted to reflect the mix of equity and debt in NiSource's capital structure as of December 31, 2007 which, he stated, was 52.43% equity and 45.57% debt. Public' Ex. JRW-5, p. 2, Panel C, Col. 1 and 3. He asserted NiSource's capitalization is the one that is used by both NiSource and NIPSCO to attract capital. *Id.* at 18. However, for the non-investor-supplied capital components of the ratemaking capital structure–customer deposits, cost-free capital and investment tax credits–Dr. Woolridge used the weights in NIPSCO's capital structure. *Id.* at 19-20; Public's Ex. JRW-5. He said use of this combination of NiSource weights and NIPSCO weights would reduce NIPSCO's revenue requirement by $29.9 million from what would be produced if NIPSCO's actual capital structure were used. *Id.* at 21.

IG Witness Michael Gorman also recommended use of NiSource's equity and debt ratios. Mr. Gorman contended NIPSCO's affiliation with NiSource has negatively affected its credit rating because NIPSCO has stronger "stand-alone metrics." Gorman Direct at 27-28. He described NiSource as "a very highly leveraged company." *Id.* at 27. Mr. Gorman asserted that NIPSCO's proposed capital structure was not reasonable because credit analysts focus on NiSource's capital structure to evaluate NIPSCO's bond ratings and NIPSCO's capital structure was "excessively expensive." *Id.* at 30. Mr. Gorman said NIPSCO's equity ratio exceeded the proxy group average, the average of 2008 major electric and gas rate decisions and the 5-year average of major electric and gas rate decisions. *Id.* at 33. Mr. Gorman maintained that NIPSCO's debt ratio is lower than what would be acceptable for an investment grade bond rating. *Id.* at 34. Mr. Gorman recommended that for ratemaking purposes the Commission use NiSource's capitalization ratios of 42.4% equity and 57.6% debt. *Id.* at 35. Mr. Gorman's NiSource equity ratio is lower and debt ratio is higher than what Dr. Woolridge used because Mr. Gorman's ratios were as of December 31, 2008 instead of December 31, 2007. Also, Mr. Gorman included NiSource debt maturing within twelve months of December 31, 2008.[1] With respect to the other components of the ratemaking capital structure, Mr. Gorman used the weights in NIPSCO's actual capital structure as of December 31, 2007.[2] Mr. Gorman testified that the NiSource debt ratios were within ranges used by S&P for a business and financial risk profile like NIPSCO's and by Moody's for bond ratings of Baa2 or Baa3. *Id.* at 36. He also described his proposed capital structure as "adequate" for NIPSCO to maintain an investment grade credit rating, financial integrity and access to capital. *Id.* at 9.

In rebuttal, NIPSCO Witness Moul responded that the OUCC and IG propose the use of a hypothetical capital structure that would provide a debt return on a significant portion of NIPSCO's capitalization that is actually common equity. He said this would be inappropriate on many levels. Moul Rebuttal at 3. Mr. Moul stated that if the Commission were to adopt the hypothetical capital structures proposed here, NIPSCO would be faced with either (a) earning significantly less than its allowed return on equity or (b) restructuring its capital structure to align it with the one used for rate-setting purposes by issuing very large amounts of new debt and using the proceeds to pay dividends to its parent company. *Id.* Furthermore, Mr. Moul explained that by using the hypothetical debt ratio in the interest synchronization calculation, the OUCC and IG also create a hypothetical interest expense deduction that decreases the income tax expense component of NIPSCO's revenue requirement. In the case of the OUCC proposal, the shortfall in income tax expense is $7.47 million.[3] Because the tax savings from the hypothetical interest is also purely hypothetical, the effect will be an even greater shortfall in NIPSCO's return on equity. *Id.* at 4. Mr. Moul provided an analysis that showed the OUCC's capital structure proposal would have the effect of reducing Dr. Woolridge's recommended 10.00% cost of equity rate to an equity return of only 8.69%. *Id.* at 4-5; Petitioner's Ex. PRM-R2, p. 2. Mr. Moul testified that the negative impact on NIPSCO would be even greater under Mr. Gorman's proposal as he treated an even larger amount of NIPSCO's common equity as if it were debt. *Id.* at 5.

Mr. Moul stated that to restructure its actual capitalization ratios to match the imputed ratios of the OUCC and IG, NIPSCO would have to issue $299.6 million of additional debt in the case of Dr. Woolridge's proposal and $418.3 million of additional debt in the case of Mr. Gorman's proposal. Then NIPSCO would be required to pay an equivalent amount of dividends. Mr. Moul emphasized issuing such large amounts of new debt will change NIPSCO's actual cost

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[1] IG Ex. MPG-3, p. 2, calculates NiSource's equity and debt ratios as of December 31, 2008 and cites the NiSource 2008 SEC Form 10-K at pages 83-84 as the source. Mr. Gorman has increased the long-term debt in his calculated 57.6% debt ratio to include $469.3 million of debt which is excluded from long-term debt on page 84 of Form 10-K and instead included under the category "current liabilities" because it is due within one year. We normally treat debt maturing within 365 days as short-term debt, not long-term debt. *See* Ind. Code § 8-1-2-76, -78. Mr. Gorman's adjustment to treat debt maturing within one year as long-term debt has the effect of inflating the NiSource long-term debt ratio and lowering the NiSource equity ratio.

[2] This can be seen by comparing IG Ex. MPG-3, p. 1, lines 4-6, col. 3 and IG Ex. MPG-1, p. 2, lines 4-6, col. 2.

[3] OUCC Witness Thomas S. Catlin quantifies this amount on Schedule TSC-4, Note 1, to his direct testimony.

of debt, which neither Dr. Woolridge nor Mr. Gorman acknowledge. He remarked that due to the turmoil that presently exists in the credit markets, this is a bad time to be issuing large amounts of debt unnecessarily. Moul Rebuttal at 5-6.

Mr. Moul also criticized the OUCC's and IG's proposals because they would impute to NIPSCO large amounts of NiSource debt that played no role in financing NIPSCO's rate base. Mr. Moul stated that at December 31, 2008, there was $1.5 billion of NiSource debt outstanding that was used to finance the acquisition of Columbia Energy Group ("CEG"), $1.0 billion of NiSource debt outstanding that was used to refinance the debentures of CEG, and $48.5 million of debt outstanding at Bay State Gas Company that was issued prior to its acquisition by NiSource. Mr. Moul testified that none of these debt amounts should play any role in the determination of the capital structure ratios for NIPSCO in this case. Moul Rebuttal at 6-7.

NIPSCO Witness Vincent V. Rea, Assistant Treasurer for NiSource, NFC and NIPSCO, also testified in opposition to the OUCC's and IG's capital structure proposals. Mr. Rea disagreed with Mr. Bolinger's opinion that NiSource was "just barely" investment grade and noted S&P had recently upgraded NiSource's outlook from negative to stable. Rea Rebuttal at 2. He further pointed out that while S&P rated NIPSCO BBB- (the same rating it assigns to NiSource), Moody's and Fitch assigned NIPSCO ratings that are higher than their NiSource ratings (Moody's Baa2 and Fitch BBB). According to Mr. Rea, the higher Moody's and Fitch ratings reflect NIPSCO's superior credit profile compared to NiSource. *Id.* Mr. Rea further commented that Moody's has said NIPSCO would be rated only "slightly higher" than its current rating on a stand-alone or independent basis. *Id.* at 3.

Mr. Rea also disagreed with Mr. Bolinger's statement that NIPSCO is "inextricably linked to NiSource" and pointed out that its relationship banks have informed NIPSCO that the marketplace would treat NIPSCO's debt securities as "structurally senior" to NiSource's debt securities and that a 10-year note offering for NIPSCO would be priced approximately 100 to 125 basis points lower than an equivalent offering by NiSource. Mr. Rea stated that when NIPSCO borrows on an intercompany basis through NFC, it receives rates very similar to those available to it in the external debt markets. Mr. Rea further explained that NIPSCO's financing costs are not exclusively dependent on credit ratings because in recent years, capital market participants have completed their own internal credit analyses to supplement and complement the work of rating agencies. He cited the rapid expansion of the use of pricing levels within the credit default swap market as demonstrating the interest of the financial marketplace in alternatives to credit ratings. Rea Rebuttal at 4-5.

Mr. Rea disputed the assertions by Mr. Bolinger, Dr. Woolridge and Mr. Gorman that NIPSCO gets little or no benefit from its strong equity ratio. He noted the information from relationship banks mentioned above shows otherwise. Despite the fact that S&P rates both companies BBB-, NIPSCO would be able to issue debt on more favorable terms than NiSource. According to Mr. Rea, this shows the marketplace clearly acknowledges NIPSCO's superior credit profile. In addition, Moody's and Fitch recognize this fact by giving NIPSCO a higher credit rating than NiSource. Mr. Rea testified that even on an intercompany basis, NIPSCO's borrowing costs are not dependent on NiSource's financial and capitalization profile. Rea Rebuttal at 5-6.

Finally, Mr. Rea noted that both the OUCC and the Commission found NIPSCO's capitalization ratios to be reasonable in NIPSCO's 2008 financing proceeding, Cause No. 43370.

Id. at 7. NIPSCO's pro forma investor-supplied capitalization ratios in that case were 59% equity and 41% debt which is comparable to the ratios in this case of 60.60% equity and 39.40% debt. Mr. Rea attributed the slight increase in the equity ratio to NIPSCO's continuing commitment to a strong capital structure in light of the Sugar Creek purchase and future capital requirements. *Id.* at 8.

(2) Discussion and Findings. NIPSCO proposes that we determine its cost of capital using its actual capital structure.[4] The OUCC and IG propose that we instead recategorize a substantial amount of NIPSCO common equity as lower cost long-term debt in order to replicate in NIPSCO's capital structure the equity and debt ratios in NiSource's capital structure,[5] which would result in a tax savings that they propose be used to reduce NIPSCO's revenue requirement. Dr. Woolridge, citing to the testimony of Mr. Catlin, indicated that the Company's revenue requirement would be reduced by $29.9 million with his capital structure. Woolridge Direct at 21. Mr. Moul indicated the OUCC's proposal would have the effect of reducing NIPSCO's actual return on equity from the 10.0% recommended by Dr. Woolridge to just 8.69% and that the shortfall under Mr. Gorman's proposal would be even greater.

Hypothetical capital structures such as those proposed here by the OUCC and IG have long been held to be contrary to Indiana law. In *Pub. Service Comm'n of Ind. v. Ind. Bell Tel. Co.*, 235 Ind. 1, 130 N.E.2d 467 (Ind. 1955) (*"Indiana Bell"*), the Indiana Supreme Court reviewed a rate order for a telephone utility (Indiana Bell) which had a 100% equity capital structure but was a subsidiary of a holding company (AT&T) that had a 50% equity and 50% debt capital structure. In the case below, the Commission reduced the utility's rate of return to reflect the parent company's cost of capital and imputed to the Indiana utility tax savings that would exist if its capital structure were two-third equity and one-third debt. 235 Ind. At 29, 130 N.E.2d at 480. The Indiana Supreme Court held the Commission's order was unlawful in both respects. Using the parent company's capital raising ability as the measure of a reasonable return was improper because Indiana Bell was "an Indiana corporation having its own separate identity even though a part of the general Bell System." 235 Ind. at 26, 130 N.E.2d at 479. The Court explained:

> Appellee is an Indiana corporation, a separate and distinct utility as defined by statute and it is the duty of the Commission to establish for it a schedule of rates which will produce a fair and non-confiscatory return upon its used and useful intrastate property, whether its stockholders are one or many, and without regard to its relationship to other companies.
>
> The fact that appellee has not used its own credit with which to raise additional capital is immaterial, and its ability to do so cannot be measured by the yardstick of the ability of the parent company to raise additional capital. The intrastate properties and operations of appellee are the ones to be considered in fixing a fair rate of return upon its used and useful property and not those of the

[4] While NIPSCO's witnesses testified that the Commission approved NIPSCO's capital structure in various financing cases, our determinations in those cases were not approvals of the utility's capital structure, but rather findings that the proposed financing was consistent with the capital structure in place at the time of the financing request.

[5] Mr. Gorman quantifies the dollar amount of his proposed shift in IG Ex. MPG-2 and IG Ex. MPG-3. There, he shows NIPSCO's actual common equity balance of $1,395,245,772 being reduced to $976,944,492, with the difference of $418,301,280 being shifted to long-term debt.

entire Bell System.

> The acts of appellants in considering the cost of money to the parent company, A.T. & T., and the "entire Bell System" rather than considering only the properties and operations of appellee is in violation of [Ind. Code § 8-1-2-6] and is unlawful.

235 Ind. at 28-29, 130 N.E.2d at 480. Similarly, the Court held the imputed tax savings adjustment was arbitrary and unlawful because it assumed "a tax saving under a capital structure which did not exist." 235 Ind. at 29-30, 130 N.E.2d at 480.

The *Indiana Bell* case was soon followed by a second capital structure decision. In *Public Service Commission of Indiana v. City of Indianapolis*, 235 Ind. 70, 131 N.E.2d 308 (Ind. 1956) ("*City of Indianapolis*"), the City, an Intervenor, challenged a Commission order granting a rate increase to Indianapolis Water Company. Among other things, the City argued that the company financed expansion of its system excessively with equity and should have issued preferred stock and bonds. In rejecting this position, our Supreme Court stated: "The statute does not permit the fixing of rates on a hypothesis or a situation never in existence." *Id.*, 235 Ind. at 91, 131 N.E.2d at 317. The Court noted that the City could have petitioned the Commission "for an order compelling the Company to engage in this financing," but noted that no such pleading was ever filed and no such order was ever issued. *Id.*, 235 Ind. at 91, 131 N.E.2d at 316.

Many examples exist of Commission Orders rejecting hypothetical capital structures, including those based on parent company capitalization ratios. *E.g.*, *Pub. Serv. Co. of Ind.*, Cause No. 28364, 37 PUR3d 485, 498-499 (Jan. 31, 1961) (rejecting the Intervenor's argument that the utility should have issued more debt as contrary to the *City of Indianapolis* case); *Ind. Bell Tel. Co.*, Cause No. 36732, p. 7, 1982 Ind. PUC LEXIS 191 at *14-15 (Sept. 7, 1982) (rejecting OUCC's proposal to use the more leveraged and less costly consolidated Bell system capital structure because "the capital structure of Petitioner as it actually exists . . . should be used in determining a fair rate of return for Petitioner"); *Indianapolis Water Co.*, Cause No. 37612, p. 17, 1985 Ind. PUC LEXIS 490 at *38 (March 20, 1985) (rejecting the OUCC's proposal to treat equity as debt because "[w]e cannot, as a matter of law, use this hypothetical capital structure to fix rates in this case"); *Hoosier Gas Corp.*, Cause No. 37541, p. 17, 1985 Ind. PUC LEXIS 522 at *34, 65 PUR4th 463, 475-476 (Feb. 28, 1985) (OUCC's proposal to use a more leveraged "typical" gas utility capital structure for cost of capital and tax expense purposes rejected as contrary to the "the statutes we are sworn to administer"); *N. Ind. Public Serv. Co.*, Cause No. 38045, p. 48, 1987 Ind. PUC LEXIS 180 at *122-123, 85 PUR4th 605, 652 (July 15, 1987) (use of pre-Bailly nuclear plant write-off equity ratio rejected as a hypothetical capital structure); *Terre Haute Gas Corp.*, Cause No. 38515, pp. 27-88, 1989 Ind. PUC LEXIS 113 at *76-78 (OUCC proposal to use a cost of equity that would reach the same result as a "proper" capital structure rejected because "[t]his Commission has consistently held in accord with Indiana law stated above that it cannot use a hypothetical capital structure to fix rates"); *Flowing Wells, Inc.*, Cause No. 38719 U, p. 7, 1989 Ind. PUC LEXIS 310 at *19 (Aug. 30, 1989) (use of parent company's debt-equity ratios rejected); *Ind. Cities Water Corp.*, Cause No. 38851, pp. 9-10, 1990 Ind. PUC LEXIS 229 at *15-16, 115 PUR4th 470, 478 (July 5, 1990) (OUCC's proposal to treat equity as debt and preferred stock at parent company's costs rejected because "artificially rais[ing] the utility's percentage of debt or artificially lower[ing] the utility's cost of equity" is inconsistent with the *Indiana Bell* case and "our guidance [from the Court] could not be clearer").

Here, the Commission finds that NIPSCO's actual capital structure shall be used to determine NIPSCO's cost of capital. Therefore, the Commission will use the capital structure set forth in Petitioner's Exhibit LEM-5 (2nd Revised), p. 1, but adjusted to include the long-term debt amount of $906,631,137 shown on Petitioner's Exhibit VVR-2, p. 1. The adjustment reflects the actual terms of the August 25, 2008 bond remarketing, which are discussed below. Rea Direct at 7.

While we approve NIPSCO's actual capital structure for purposes of determining NIPSCO's weighted cost of capital in this Cause, we note that NIPSCO is approaching the edge of what this Commission finds to be a reasonable capital structure for a large investor-owned electric utility. Going forward, we would encourage NIPSCO to take prudent steps to reduce its equity to debt ratio.

B. Cost of Capital.

(1) Petitioner's Evidence. Ms. Miller calculated NIPSCO's weighted cost of capital to be 8.37%, based on NIPSCO's December 31, 2007 actual capital structure, as adjusted, a debt cost rate of 6.56% and a common equity cost rate of 12.00%. Miller Direct at 44; Petitioner's Ex. LEM-5 (2nd Revised), p. 1. The 6.56% debt cost rate included an estimate of the interest rate and transaction costs that would be incurred in remarketing $254 million of Jasper County tax-exempt bonds. Rea Direct at 7. Mr. Rea testified that the remarketing occurred only four days before NIPSCO's case-in-chief was to be filed and NIPSCO did not have time to revise its case-in-chief to incorporate the actual terms. However, he provided a schedule showing the effect on the amount of debt and the weighted cost of debt when the Jasper County debt cost estimates were trued-up to actual. Id. at 7-8; Petitioner's Ex. VVR-2, p. 1. There was only a minor difference, i.e., $906,631,137 instead of $906,997,137 and 6.52% instead of 6.56%. Dr. Woolridge used the estimated 6.56% debt rate. Public's Ex. JRW-1. Mr. Gorman used the actual amount and rate. IG Ex. MPG-1. Although the impact on NIPSCO's cost of capital is very slight, we find the actual amount and rate shown in Petitioner's Exhibit VVR-2, p. 1, should be used in determining NIPSCO's cost of capital.

NIPSCO proposed a cost of common equity rate of 12.00% through the testimony of Mr. Moul. Mr. Moul considered the risk factors that affect electric utilities in general and NIPSCO in particular. He noted that electric utilities, including NIPSCO, face substantial increases in operating and capital costs due to increasingly stringent environmental regulations including future greenhouse gas regulation. He noted environmental investments increase risk without adding to a utility's generating capacity and this risk is aggravated by the "moving target" nature of evolving environmental regulation. He said NIPSCO's risk profile is strongly influenced by the magnitude of its sales to industrial customers that represent 53% of its sales in kWh but are less than 1% of its customers. Mr. Moul testified that NIPSCO's industrial sales far exceed the utility average. He said 64% of NIPSCO's industrial sales are to steel-related industries that face international competition, increased costs and fluctuating demand for their products. Mr. Moul pointed out that the credit rating agencies have cited Indiana's high level of industrial employment and high concentration of steel, chemical, metals, auto parts and refining businesses as creating risks for NIPSCO. According to Mr. Moul, NIPSCO is exposed to significant sales and bad debt risk because of the magnitude of its industrial load and the reliance of its service area on heavy industry. Moul Direct at 7-8. Mr. Moul also discussed NIPSCO's substantial future capital expenditure requirements and stated a fair rate of return will be key to attracting the capital necessary to meet NIPSCO's needs. *Id.* at 9.

Mr. Moul developed a proxy group of publicly traded utility companies ("Electric Group" or "Group") for use in the models he applied to estimate NIPSCO's cost of equity. These companies are all included in Value Line Investment Survey ("Value Line"), have electric utility subsidiaries that are Midwest ISO members or formerly had transmission assets that were transferred to separate Midwest ISO-participating transmission companies, have not recently reduced their common dividend and are not the target of a merger or acquisition. Moul Direct at 4; Petitioner's Ex. PRM-2, p. 7. Mr. Moul then compared NIPSCO and the Group with respect to nine separate risk factors. He concluded that on some counts NIPSCO's risk is higher than the Group and on other counts lower or approximately equal. On balance, he considered the factors to average out so that, in Mr. Moul's opinion, the Group provides a reasonable basis for measuring NIPSCO's cost of equity.

Mr. Moul first applied the discounted cash flow approach. This model considers the cost of equity to be equal to a stock's dividend yield plus expected long-term growth. In applying the model, Mr. Moul used a divided yield of 4.54% based on the average dividend yield for the Electric Group for the six months ended May 2008 adjusted to a forward-looking basis using three generally accepted methods to reflect the prospective nature of dividends. Mr. Moul used a growth rate of 6.50% after analyzing historical and forecasted per share growth in earnings, dividends, book value and cash flow for the members of the Electric Group. Mr. Moul gave the greatest emphasis to projected earnings per share ("EPS") growth because he considered it to be the principal focus of investor expectations. Moul Direct at 18-19.

Mr. Moul said the historical rates were not good measures for the Electric Group because they include many negative rates of change that provide no reliable guide to gauge investor expectation of future growth. He explained rational investors expect positive returns on their investments. Moul Direct at 22. Mr. Moul commented that Professor Myron Gordon, the foremost proponent of the use of the DCF model in rate cases, concluded EPS forecasts were the best measure of the DCF growth rate. *Id.* at 25. Mr. Moul added a flotation cost adjustment of 0.17% to cover issuance expenses. *Id.* at 28; Petitioner's Ex. PRM-1, Appendix E. To support the flotation cost adjustment, Mr. Moul provided issuance expenses in public offerings of electric utility stocks from 2003 to 2007. Petitioner's Ex. PRM-2, p. 14, Sch. 8. The result of Mr. Moul's DCF analysis was a cost of equity rate of 11.21%, i.e., 4.54% + 6.50% + 0.17. *Id.*

Mr. Moul also performed a risk premium analysis. This method determines the cost of equity by adding a premium to corporate bond yields to account for the fact that the equity investor is exposed to greater risk than debt capital. Moul Direct at 28-29. In this approach, Mr. Moul used a 6.00% estimate of the prospective yield on long-term A-rated public utility bonds. The 6.00% yield was based on consensus forecasts of 30-year treasury bond yields reported in Blue Chip Financial Forecasts ("Blue Chip") plus 1.50% representing the spread between returns on utility bonds and treasury bonds during recent three month, six month and twelve month periods. *Id.* at 30. Mr. Moul developed a 5.50% equity risk premium by first comparing the difference in market returns on utility stocks in the S&P Public Utility Index and market returns on utility bonds during four different historical time periods, each of which began with a financial market defining event. Mr. Moul then made a downward adjustment for the risk differences between the S&P Public Utility Index and his Electric Group. *Id.* at 32-33. He then added the 0.17% flotation cost adjustment to derive a risk premium result of 11.67, i.e., 6.00% + 5.50% + 0.17%. Moul Direct at 34.

Mr. Moul also applied the Capital Asset Pricing Model ("CAPM") approach which measures the cost of equity as the yield on a risk-free interest bearing obligation plus an equity risk premium proportional to the non-diversifiable or systematic risk of an investment. Moul Direct at 34; Petitioner's Ex. PRM-1, Appendix H, p. H-1. Mr. Moul used a 4.50% risk-free rate based on recent historical yields on long-term treasury bonds, Blue Chip forecasts and the recent trend. *Id.* at 35-36. In the CAPM, systematic risk is represented by a company's beta which measures how the stock price changes compared to the overall market. Mr. Moul used a beta of 0.85 which is the average of the Value Line betas for the companies in the Electric Group. *Id.* at 35. Mr. Moul selected a market premium of 8.44% by averaging the difference between (a) historical market returns and treasury bond returns (6.5%) and (b) the difference between forecasted market returns and treasury bond returns (10.37%). The historical market premium was derived from data published by Ibbotson Associates in Stocks, Bonds, Bills and Inflation Yearbook ("SBBI") for the period 1926-2007. Mr. Moul said arithmetic mean returns were used because the CAPM is a single period model. He quoted an explanation from SBBI as to why arithmetic returns must be used. Petitioner's Ex. PRM-1, Appendix H, p. H-6. Mr. Moul added a size premium of 0.92% to adjust for the size of the Electric Group. This adjustment reflects the size premium for mid-capitalization stocks published in SBBI. He also added the 0.17% flotation cost adjustment. These inputs produced a CAPM result of 12.76%, i.e., 4.50% + (0.85 × 8.44%) + 0.92% + 0.17%.

Mr. Moul also pointed out that in *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n*, 262 U.S. 679 (1923), the United States Supreme Court held a public utility is entitled to rates that will permit it to earn a return on the value of its property equal to that generally being made on investments in other business undertakings which are attended by corresponding risks. Therefore, Mr. Moul testified, it is important to identify the returns earned by comparable risk companies that compete for capital with the public utility and are subject to competitive marketplace forces. Moul Direct at 38-39. To implement this approach, Mr. Moul applied the following screening criteria to identify non-utility companies followed by Value Line that reflect the risk of the Electric Group – Timeliness Rank, Safety Rank, Financial Strength, Price Stability, Betas and Technical Rank. *Id.* at 39. Mr. Moul considered a ten year business cycle for these firms consisting of five historical years and five projected years. The historical return on equity of 15.4% and the projected return on equity of 16.0% were averaged to produce a Comparable Earnings result of 15.70%. *Id.* at 40-41.

Mr. Moul then considered the results of each of his approaches to analyzing NIPSCO's cost of equity. He recommended that the Commission find a cost of common equity for NIPSCO of 12.00% to be reasonable. He explained that the average of the DCF and CAPM results were 11.99%, the average of the three market models (DCF, CAPM and Risk Premium) was 11.88% and the average of all four methods was 12.84%. Moul Direct at 6. Mr. Moul said his proposed 12.00% cost of equity made no provision for the prospect that the rate of return may not be achieved due to unforeseen events such as unexpected spikes in costs, abrupt changes in customer usage and abnormal weather. *Id.*

(2) OUCC's Evidence. Dr. Woolridge testified in support of the OUCC's recommendation that the Commission find NIPSCO's cost of common equity to be 10.00%. Dr. Woolridge first discussed the effect of the current financial crisis on the difference

in yields on treasury bonds and utility bonds, noting that the differential increased significantly due to tightening credit markets and the flight to quality that drove treasury yields to historic lows. But he stated the differential has declined over the past several months. Woolridge Direct at 7. Dr. Woolridge recognized that the credit market for corporate and utility debt experienced higher rates due to the credit crisis and that the long-term market remains tight, but he said the market has improved in response to unprecedented actions by the federal government. Id. at 10-11. Dr. Woolridge expressed his opinion that the Obama administration is committed to bringing the economy around, utilities are likely to benefit under an Obama administration, the worst of the credit crisis appears to be over and credit spreads, while still high, have declined. Id. at 11-12. Dr. Woolridge asserted his viewpoint that the volatility of stocks relative to bonds has declined recently and relied on an article authored by employees of McKinsey & Co., a consulting firm, expressing the opinion that the financial crisis has not significantly changed McKinsey's long-term estimate of the equity risk premium.[6] Id. at 12-14. Dr. Woolridge also believed utility stocks have held up well compared to the overall market. Id. at 15.

Dr. Woolridge used two market-based models to estimate NIPSCO's cost of equity – a DCF model and a CAPM. To apply these models, he selected a nine member Electric Proxy Group consisting of companies that are listed as an electric utility or combination electric and gas company by AUS Utility Reports, listed as an electric utility by Value Line, have at least 75% regulated electric revenues, have operating revenues less than $10 billion, have a 3-year history of paying dividends with no actual or pending cuts, and have an investment grade bond rating. Woolridge Direct at 15-16.

Before applying his models, Dr. Woolridge testified that in equilibrium the market value of a firm's securities will be equal to book value and that when a firm earns a return on equity in excess of its cost of equity, investors respond by valuing the firm's equity in excess of book value. Woolridge Direct at 23-24. In support, he cited a 1988 article by the founder of consulting firm Marakon Associates that said the value of a company is determined by its cash flow which is in turn affected by its return on equity and a 1987 Harvard Business School case study which concluded higher returns on equity provide higher market-to-book ratios. *Id.* 23-24.

Dr. Woolridge said he relies primarily on the DCF model to estimate the cost of equity capital. Woolridge Direct at 29. In his DCF analysis, he used a dividend yield of 5.4% which is the mid-point of the proxy group average for the six months ending April 2009 and the proxy group average in April 2009, adjusted for one-half year of expected growth. *Id.* at 33; Public's Ex. JRW-10, p. 1. Dr. Woolridge selected a growth rate of 5.0% after considering historical growth rates for the proxy companies in EPS, dividends per share ("DPS") and book value per share ("BVPS") as measured by both means and medians. He also considered Value Line's projections of EPS, DPS and BVPS, projected internal growth rates calculated by Dr. Woolridge from Value Line's projected retention rate and return on equity, and analyst EPS growth rate forecasts. *Id.* at 36-38. However, he discounted the analyst forecasts because of his belief that

[6] Dr. Woolridge referred to this document as a study. A review of his workpapers shows he relies upon a 5 ½ page document on a McKinsey website expressing the subjective opinion that "there is no evidence of a substantial increase in the cost of long-term capital" but which acknowledges: "we cannot be certain that its cost will not increase over the next several years as the recession develops," cash flow "uncertainty has increased significantly," and "[i]t is particularly unclear what a normal level of growth and returns on capital will be in the future." *Id.* at pp. 5, 6.

they have an upward bias. *Id.* at 39. His DCF result was a common equity cost rate for NIPSCO of 10.4%, i.e., 5.4% + 5.0%.

In his CAPM, Dr. Woolridge used a risk free rate of 4.00% which was the upper end of the range of yields in 10-year and 20-year treasury bonds that he thought was reasonable for the near future. *Id.* at 43. He used a beta of 0.68 which was his proxy group average. *Id.* at 44; Public's Ex. JRW-11, p. 3. Dr. Woolridge used an equity risk premium of 4.61%. He stated that the "traditional way" to measure the equity risk premium was to use the difference between historical average stock and bond returns. This approach, Dr. Woolridge said, is often called the "Ibbotson approach" after Professor Roger Ibbotson, and usually suggests an equity risk premium of 5%-7% above the long-term treasury bond rate. *Id.* at 45. Dr. Woolridge asserted that some academic studies using "ex ante models" and "puzzle research" compute lower expected returns using market data without regard to historical returns. *Id.* at 46-48. According to Dr. Woolridge, the historical returns are "biased upwards" because "the expected equity risk premium has declined [as] stock prices have risen." *Id.* at 48. Dr. Woolridge's equity risk premium of 4.61% is an average of four different averages: (a) seven historical studies for periods beginning as early as 1872, most with both arithmetic results and geometric results included in the average; (b) 25 ex ante puzzle research studies, many with multiple low, high and midpoint results, published between 1999 and 2009; (c) four surveys of forecasters, Chief Financial Officers and academics; and (d) two estimates using the "building blocks" methodology, one of which was performed by Dr. Woolridge for this case. Public's Ex. JRW-11, p. 5. Dr. Woolridge's building blocks calculation derived an expected equity return for the market of 7.90% by adding a real growth rate of 2.50%, a dividend yield of 3.00% and an inflation rate 2.40%. Public's Ex. JRW-11, p. 7. Dr. Woolridge then deducted a recent 30-year treasury yield rate of 3.83% to derive an equity risk premium of 4.07%. *Id.* at 55-56. However, this is but one of 83 percentages included in the averages and averages of averages used to compute his 4.61% equity risk premium. Public's Ex. JRW-11, p. 5. Using the equity risk premium of 4.61%, Dr. Woolridge computed a CAPM result of 7.1%, i.e., 4.00% + (0.68 × 4.61%).

Although his calculated range was 7.1%-10.4%, Dr. Woolridge recommended an equity cost rate of 10.0% for NIPSCO, stating that the upper end of the range should be used due to the current volatile capital market conditions. Woolridge Direct at 59.

Dr. Woolridge also discussed his disagreements with Mr. Moul's testimony. With respect to the proxy group, Dr. Woolridge said Mr. Moul's Electric Group companies were not particularly good proxies for NIPSCO because five were combination gas and electric companies with an average only 57% of revenues from electric operations. He cited Avista, CMS, Integrys, NiSource and Vectren as companies with substantial gas operations. He also said Mr. Moul's group had lower common equity ratios and higher coefficients of variation of earned returns on common equity than NIPSCO. Woolridge Direct at 63-64.

With respect to Mr. Moul's DCF analysis, Dr. Woolridge criticized Mr. Moul's adjustment to state the dividend yield on a forward-looking basis by compounding quarterly dividends to the end of the year. Dr. Woolridge argued that compounding should not be used because the investor has the option of reinvesting the dividends as he or she chooses. Woolridge Direct at 66. Dr. Woolridge also criticized Mr. Moul's 6.50% growth rate on the ground that it gave too much weight to analysts' forecasts of EPS growth. Dr. Woolridge contended analysts' forecasts are overly optimistic and biased upwards. Dr. Woolridge said this was demonstrated by a comparison he made of forecast and actual EPS growth rates since 1988 for the companies in the I/B/E/S data base. *Id.* at 68. Dr. Woolridge maintained that his findings indicated forecast errors for the long-term estimates were predominately positive which he interpreted as showing upward bias. *Id.* at 69. Although he recognized that analysts' EPS growth rate forecasts have subsided somewhat since 2000 and new regulations against conflicts of interest were adopted in 2003, in Dr. Woolridge's opinion, analysts' forecasts continue to be overly optimistic. *Id.* at 70. In support, he cited two Wall Street Journal articles, one of which reported on Dr. Woolridge's opinions about Wall Street analysts. *Id.* at 70-71; Public's Ex. JRW-13, p. 4. Dr. Woolridge testified that the upward bias is not as pronounced for electric utility companies but, in his opinion, analysts' projected electric growth rates still exceed the actual rates. *Id.* at 71-72. Dr. Woolridge also believes Value Line is upwardly biased which he attributed to its reluctance to forecast negative growth rates. *Id.* at 73.

Dr. Woolridge also opposed Mr. Moul's flotation cost adjustment on a variety of grounds: the Company has not identified any flotation costs; investors are not entitled to flotation costs when market prices exceed book value; underwriting spreads need not be recovered through the regulatory process; and brokerage fees that investors pay in secondary market transaction are not included in the DCF analysis. Woolridge Direct at 73-75.

Dr. Woolridge opposed Mr. Moul's use of a risk premium analysis because utility bonds are subject to interest rate risk and credit risk which do not apply to equity investors. *Id.* at 76. He reiterated his position discussed above that risk premiums based on historical returns are overstated. *Id.* at 77. He also contended historical bond returns were biased downward because of capital losses; geometric means only should be used; investors could not achieve the historical market returns because of transaction costs and without rebalancing their portfolios every month; stock index returns are affected by survivorship bias and the "Peso Problem" (less disruption in U.S. markets than other markets around the world); and market conditions today are different than in the past which has resulted in a decrease in the equity premium over bond yields. *Id.* at 78-87.

With respect to Mr. Moul's CAPM, Dr. Woolridge contended Mr. Moul's risk-free rate was overstated. He objected to the consideration of historic risk premiums for reasons previously mentioned. He also criticized Mr. Moul's prospective risk premium because of its reliance on forecasts of EPS growth by analysts and by Value Line (both of which Dr. Woolridge deems to be upwardly biased), because Mr. Moul considered only dividend-paying stocks and because the stocks are weighted equally. Woolridge Direct at 89-92. He said Mr. Moul's use of an 11.29% growth rate in his calculation of the prospective equity risk premium is excessive because it exceeds the historical nominal growth rate in gross domestic product ("GDP") of 7.20%. *Id.* at 93. Dr. Woolridge also asserted Mr. Moul's size adjustment is inappropriate for regulated electric utilities. *Id.* at 95-96.

Dr. Woolridge disagreed with Mr. Moul's Comparable Earnings analysis on the basis that it did not measure long-term earnings expectations. *Id.* at 97.

(3) IG's Evidence. IG Witness Michael Gorman used multiple methods to estimate NIPSCO's cost of common equity–three different versions of the DCF model, two versions of the Risk Premium model, and the CAPM. In applying his models, he used the same proxy group as Mr. Moul. Mr. Gorman recommended that the Commission find

that NIPSCO's cost of common equity is 10.3% with a capital structure that uses NiSource's capitalization ratios and 9.8% with NIPSCO's actual capital structure.

Mr. Gorman first used a constant growth DCF model with a dividend yield of 5.93% and a growth rate of 6.00% resulting in a cost of equity estimate of 11.77%. The dividend yield was calculated from average stock prices during the 13-week period ended March 13, 2009 and annualized dividends adjusted for next year's growth. Gorman Direct at 40-41. The growth rate came from security analysts' earnings growth forecasts available on March 17, 2009. *Id.* at 42. Mr. Gorman testified that analysts' forecasts have been shown to be more accurate predictors of future returns than growth rates derived from historical data and influence stock observable prices more than historical data. *Id.* at 41-42. The average forecast growth rate for the proxy group was 8.99%. *Id.* at 43. However, Mr. Gorman believed this growth rate was too high and substituted a 6.00% growth rate, which was the median of the proxy group growth rates. He said use of this lower growth rate was appropriate because it excluded the impact of the two highest growth rates (Empire District and Integrys) and was more consistent with consensus projections of GDP growth that he believed should be a "ceiling" on a utility's growth rate. *Id.* at 44. He said economists expect GDP growth over the next five to ten years of no more than 5.1%. *Id.* at 43. In support of his position that there should be a GDP growth ceiling on a utility's growth rate, Mr. Gorman cited the 2007 edition of the Brigham and Houston text, Fundamentals of Financial Management. *Id.* at 45. During cross-examination, Mr. Gorman stated he deleted from the quote in his testimony a statement by the authors on a GDP growth basis one might expect the dividends of an average or normal company to grow at a rate of 5% to 8% a year. Tr. at DD-80. Mr. Gorman said he deleted this statement because it was based on outdated information, and he did not believe the authors would have that same view today. Tr. at DD-80–DD-82.

Mr. Gorman also contended that even after substituting the lower median for the average, the 6.00% growth rate was not sustainable. Therefore, he performed a second DCF calculation using a growth rate of 4.21% which he said was the sustainable growth rate.[7] This rate was based on Value Line projections of returns on equity, payout ratios and earnings retention. *Id.* at 47. The result of the "sustainable growth" DCF model was 10.13%.

Mr. Gorman also performed a third DCF calculation that used decreasing growth rates for (a) the first five-years, (b) the next five-years and (c) year 11 through perpetuity. *Id.* at 48. The rates used in the first stage were the analysts' forecasts described above; the rates used in the second stage represented the difference between the analysts' forecasts and the Blue Chip 5 to 10 year GDP growth projection of 5.1%; and the rate used in the third stage (year 11 forward) was the 5.1% GDP growth estimate. Gorman Direct at 49. The result of the multi-stage DCF model was 11.23%. *Id.* at 50.

For his ultimate DCF recommendation, Mr. Gorman averaged his sustainable growth and multi-stage DCF results (10.13% and 11.23%) and rounded the average up to 10.70%. *Id.* at 50.

In his Risk Premium models, Mr. Gorman calculated the difference between regulatory commission-authorized returns for electric utilities in each year since 1988 as reported by

[7] Mr. Gorman's testimony states that he used a 4.21% sustainable growth rate to derive a 10.13% DCF result. Gorman Direct at 48. However, IG Ex. MPG-13 appears to show that a growth rate of only 3.77% was used in the 10.13% calculation.

Regulatory Research Associates and average yields on treasury bonds and A-rated utility bonds in each of those same years. This method produced an average risk premium over treasury bonds of 5.10% and over A-rated utility bonds of 3.68%. IG Ex. MPG-16; IG Ex. MPG-17. Mr. Gorman then selected ranges of 4.40% to 6.01% for the treasury spread and 3.03% to 4.39% for the utility bond spread by focusing on where most of the annual results fell. Gorman Direct at 52. Mr. Gorman then added the treasury risk premium range to a projected treasury bond yield of 4.30% and the utility bond risk premium range to a current 13-week average yield on A-rated and Baa-rated utility bonds of 7.85%. From these results, Mr. Gorman recommended a 9.91% rate for the treasury bonds analysis (a rate between the mid-point and high end of his range) and a rate of 10.40% for the utility bond analysis (the low end of his range). *Id.* at 54-55. Mr. Gorman said he used the low end of the utility bond range to reflect his belief that yields would decline to more normal levels once economic conditions strengthen. *Id.* at 55.

In his CAPM, Mr. Gorman used a 4.30% risk-free rate based upon a Blue Chip projected treasury bond yield and a beta of 0.73 based on the average of the Value Line proxy group beta estimates. Gorman Direct at 56, 57. Mr. Gorman derived a forward looking market risk premium of 7.00% and a historical market risk premium of 6.50%. *Id.* at 58. The forward looking premium was determined by subtracting the 4.30% risk-free rate from Mr. Gorman's estimate of the expected return on the S&P 500 Index which was calculated by adding an estimated inflation rate of 2.1% to the long-term historical arithmetic average real return on the market as reported in the Valuation Edition of SBBI. Mr. Gorman's CAPM results are 9.05% to 9.41% with a midpoint of 9.20%. *Id.* at 60.

Based on the results of all of his analyses, Mr. Gorman recommended a return on equity range of 9.80% to 10.70% with the low end being the average of his risk Premium and CAPM results and the upper end being his DCF result. Gorman Direct at 61. He testified that if NIPSCO's actual capital structure was used (as proposed by NIPSCO), he recommended 9.80%, the low end of the range, because there is less financial risk. But if his proposed NiSource capital structure is used, he recommended 10.30%, the midpoint of his range. *Id.* Mr. Gorman contended his recommendations would support investment grade credit ratings under S&P's credit metric benchmarks. *Id.* at 62. However, he acknowledged S&P's new credit metrics are not as transparent as its former metrics and do not clearly identify utility-specific credit metric guidance ranges based on its business risk assessment. *Id.* at 62.

Mr. Gorman also commented on Mr. Moul's testimony. He said Mr. Moul's DCF growth rate of 6.50% was too high to be sustainable in the long run. Mr. Gorman asserted academics have found, and investors understand, long-term sustainable growth cannot exceed GDP growth over sustained periods of time. Gorman Direct at 74-75. Mr. Gorman argued the financial risk of a utility is based on book value leverage, not market value leverage, and analysts do not consider market value leverage to be of significance. *Id.* at 71. He said Mr. Moul's flotation cost adjustment was not appropriate because it was not based on NIPSCO's actual expenses. *Id.* at 73.

Mr. Gorman disputed the 5.50% risk premium used by Mr. Moul in the Risk Premium approach on the ground it was not based on observable and verifiable market evidence of NIPSCO's risk as compared to the proxy group. *Id.* at 77.

Mr. Gorman also objected to Mr. Moul's size adjustment in the CAPM. According to Mr. Gorman, a size adjustment is not proper because the SBBI mid-cap deciles used in the adjustment include stocks with an average beta of 1.12 which is higher than the proxy group. *Id.* at 79. Mr. Gorman concurred with Mr. Moul's historical market risk premium of 6.50% but considered his prospective market risk premium of 10.37% to be excessive because the Value Line and S&P growth used by Mr. Moul project growth in excess of GDP growth.

Finally, Mr. Gorman disagreed with Mr. Moul's Comparable Earnings analysis on the grounds that it measures book returns instead of market required returns and includes non-regulated companies not comparable to NIPSCO. *Id.* at 82.

(4) Petitioner's Rebuttal Evidence. Mr. Moul responded to Dr. Woolridge's discussion of the credit crisis. Mr. Moul said that in response to the credit crisis investors have become more risk adverse thereby increasing their required return. He explained that market volatility is much higher than it was prior to the beginning of the financial crisis and yield spreads and debt costs have increased. Mr. Moul testified attracting capital would be more difficult for NIPSCO if the Commission accepted the returns proposed by Dr. Woolridge and Mr. Gorman. Moul Rebuttal at 8-11. Mr. Moul also provided updates of this cost of equity models using the latest information available. His updated results were as follows:

	Direct Testimony	Update
DCF	11.21%	12.62%
RP	11.67%	12.44%
CAPM	12.76%	11.24%
Comparable Earnings	15.70%	14.30%
Average	12.84%	12.65%
Median	12.22%	12.53%
Mid-point	13.46%	12.77%

Id. at 12. He said the DCF and Risk Premium results increased because of increasing dividend yields and widening spreads over treasury yields. The CAPM result declined due to lower betas and a reduction in the market premium. The Comparable Earnings result was lower because of the recession. Because the average of the market-based models is 12.10% and the average of the DCF and CAPM methods is 11.93%, Mr. Moul concluded a rate of return of no less than 12.00% is still reasonable. Id. at 12-13.

Mr. Moul criticized Dr. Woolridge's proxy group because the companies have few characteristics that are comparable to NIPSCO. He said Dr. Woolridge should have considered combination companies and should not have included companies with speculative bond ratings, delivery-only utilities and utilities with significant hydro generation. Moul Rebuttal at 14-15.

Mr. Moul described Dr. Woolridge's criticism of Mr. Moul's quarterly compounding method of determining the dividend yield in the DCF as a "tempest in a teapot" because Dr. Woolridge's method produces precisely the same result. Moul Rebuttal at 16. However, for purposes of his rebuttal, Mr. Moul used Dr. Woolridge's method in his rebuttal updates. Id.

Mr. Moul reaffirmed his position that analysts' forecasts of EPS growth are the best measure of growth in the DCF model and should be given primary weight. He said they are the primary determinant of investor expectations. Moul Rebuttal at 16-17.

Mr. Moul noted that the results of Mr. Gorman's constant growth DCF model (the form previously used by this Commission) and Mr. Gorman's multi-stage model are both well above 11%. Moul Rebuttal at 17-18. He cited eight factors that contribute to investors' expectations of earnings growth that are not considered by Mr. Gorman's "sustainable" or "retention growth" model which only considers book value changes and accretion from the sale of stock. Id. at 18. Mr. Moul asserted BVPS growth, or its surrogate retention growth, does not represent a proper financial variable because utility stocks typically do not trade at book value. Id. at 8-19. Mr. Moul also said Mr. Gorman relies on projections not shown to be sustainable beyond the identified periods and has not provided recognition of transition growth through 2012 and growth beyond 2014. Id. at 19. Further, Mr. Gorman's result is entirely dependent upon his assumed return on equity of 10.15%. According to Mr. Moul, that is like having to know the end result in order to calculate it. Id. at 20.

Mr. Moul testified that Mr. Gorman has been inconsistent in his use of the multi-stage DCF model, citing cases since 2001 where Mr. Gorman used the model and others where he did not. Mr. Moul rejected Mr. Gorman's opinion that analysts' earnings forecasts cannot be reasonable estimates when in excess of current 5 and 10 years forecasts of GDP growth. Mr. Moul said Mr. Gorman has not shown any cause and effect relationship or linkage of these variables. Mr. Moul said one could as easily assume dividend growth and GDP growth understate investors' expectations of proxy group growth, thereby showing the need to use analysts' forecasts. Id. at 19-22.

Mr. Moul testified GDP growth is not the sole determinant of earnings growth. He described GDP as having a "product side" and an "income side," both of which are made up of many components. He contrasted Mr. Gorman's 5.1% GDP growth rate with Value Line's Industrial Composite earnings growth forecast of 6.5% and Blue Chip's forecasts of growth in pre-tax profits of 7.0% for 2011-2015 and 5.5% for 2016-2020. Mr. Moul said this showed future corporate profit growth will exceed GDP growth which has also been true historically. Moul Rebuttal at 22-23. Mr. Moul also pointed out FERC has rejected use of a two-stage DCF model for electric companies because objective measures showed electric companies do not display growth characteristics that fit a multi-stage model. Id. at 23. While FERC does use a two-stage model for natural gas pipelines, Mr. Moul showed that the FERC approach, if followed here, would raise Mr. Gorman's median result to 11.44% and his group average to 13.74%. Id. at 24.

Mr. Moul disputed Dr. Woolridge's contention that analysts' forecasts of EPS growth are biased. He considered Dr. Woolridge's opinions out-of-date because of the 2003 final judgment in the Global Research Analyst Settlement required Wall Street firms to separate their research and investment banking services. Moul Rebuttal at 25. Mr. Moul also considered Dr. Woolridge's position on analyst bias to be inconsistent with his DCF model which uses analysts' forecasts (Public's Ex. JRW-10, pp. 4 and 5) and Dr. Woolridge's reliance on the Claus and Thomas study that measures expected cash flow by using analysts' forecasts (Woolridge Direct at 25-26). Finally, Mr. Moul testified that regardless of what Dr. Woolridge thinks about their accuracy, analysts' forecasts are what investors actually use in their decisions to buy, sell or hold stocks. Id. at 26. Even if there were bias suggesting a downward adjustment might be appropriate, stock prices would likewise require a downward adjustment because the growth rate must be synchronized with the price investors establish when valuing a stock. Id. at 26.

Mr. Moul criticized Dr. Woolridge's use of Value Line DPS forecasts in determining the DCF growth rate. Mr. Moul said the low DPS growth rates are attributable to Value Line's forecast of declining dividend payout ratios for Dr. Woolridge's proxy companies. Moul Rebuttal at 26. With respect to Dr. Woolridge's reliance on historical growth rates, Mr. Moul said analysts consider historical growth rates in the process of developing forecasted growth rates to assess how the future may diverge from historical practices. Id. at 27. Mr. Moul disagreed with the retention ratios of Dr. Woolridge and Mr. Gorman because they did not convert year-end book values to average book values in determining the return on equity. Mr. Moul said this causes an understatement of retention growth and that FERC requires this adjustment. Id. at 28-29. Mr. Moul testified Dr. Woolridge's and Mr. Gorman's retention growth calculations have an additional downward bias because they ignore future growth from external stock financing. Id. at 29.

Mr. Moul testified the analysts' forecasts of EPS growth for Dr. Woolridge's proxy companies average 6.52% and, if this rate of growth is used in Dr. Woolridge's DCF model, the result is an common equity cost rate of 11.99%. Moul Rebuttal at 29-30.

Mr. Moul said a flotation cost adjustment is appropriate because Value Line forecasts show the utilities will be issuing new common stock in the future and that has been historically true. Moul Rebuttal at 30. Mr. Moul stated flotation costs must be considered because only stock sale proceeds net of the underwriting spread and out-of-pocket expenses are available for utility investments. Id.

Mr. Moul criticized Dr. Woolridge for not using the Risk Premium method because it considers a company's own borrowing rate. Moreover, the Risk Premium approach considers additional risk, which is not reflected in the beta measure of systematic risk. Moul Rebuttal at 31. Mr. Moul believed this method was particularly pertinent today because of the credit crisis, which has significantly affected utility debt costs. Id. at 31-32. While Mr. Gorman used the Risk Premium method, his use of regulatory authorized returns to determine the risk premium is of limited usefulness because it reflects an arbitrary time period beginning in 1986. Id. at 32. Mr. Moul showed Mr. Gorman's premiums would be substantially higher if authorized returns since 1999 or 2004 were used. Id. Mr. Moul also said Mr. Gorman's approach was deficient because it mixed book equity returns with market-determined bond yields; does not synchronize the rate orders with the time of the evidentiary record (creating a potential time period mismatch); authorized returns do not necessarily reflect investor-required returns because they can be influenced by policy, political factors and regulatory practices; and past authorized returns do not reflect the risks faced by electric utilities today. Id. at 32-33.

Mr. Moul disagreed with each of the reasons Dr. Woolridge raised against the Risk Premium method. Mr. Moul also elaborated on the justification for using arithmetic means in the Risk Premium method. Moul Rebuttal at 34-38.

With respect to Dr. Woolridge's opinion that the risk return relationship that existed in the past no longer applies today, Mr. Moul provided a graph showing the historical performance of the Chicago Board of Options Exchange Volatility Index ("VIX") since 1990. Moul Rebuttal at 39-40. Because the volatility of the market is higher today (as shown by the VIX), Mr. Moul concluded there has been no shrinkage in the equity risk premium. Id. at 41.

Although Mr. Moul agreed with the historical equity risk premium used by Mr. Gorman in the CAPM, he criticized Mr. Gorman for failing to also consider a prospective premium that reflected expected future market returns. Moul Rebuttal at 41. Mr. Moul criticized both Mr. Gorman and Dr. Woolridge for failing to include a size adjustment in their CAPM calculations. Mr. Moul described Dr. Woolridge's 7.1% CAPM result as "simply not credible" as evidenced by the fact that it is lower than the May 2009 Baa-rated utility bond yield of 7.76%. Id. at 42. He said Dr. Woolridge's CAPM assumes an expected market return of only 7.90% (Woolridge Direct at 54, l. 8), which is totally unrealistic as shown by Value Line's Industrial Composite forecasts. Id. at 43. Because Dr. Woolridge computes a DCF return for his proxy group of 10.4%, Mr. Moul said it is not possible for the total market return to be only 7.9%. Id. at 44.

With respect to the size adjustment, Mr. Moul testified that, contrary to Dr. Woolridge's opinion, the beta of the SBBI mid-cap decile provides no basis to reject the adjustment. He opined the Wong article relied on by Dr. Woolridge is not relevant because it relies on data going back to the 1960s when the utility business was fundamentally different. He cited the famous Fama/French study as identifying size as a separate risk factor not compensated for by the beta. Moul Rebuttal at 44-45.

Mr. Moul defended his Comparable Earnings analysis on the ground that it was supported by the underlying premise of rate regulation and was consistent with the views of the financial community that the regulatory process must consider returns achieved by the non-regulated sector to ensure regulated companies can compete effectively in the capital markets. Moul Rebuttal at 46. He noted investors would not be motivated by an opportunity to earn a 10% return for NIPSCO when they could obtain higher returns on alternative investment opportunities of equal risk. Id. at 46. Mr. Moul disputed Dr. Woolridge's contention that low cost of equity rates can be justified because market-to-book ratios typically exceed 1.0. Id. at 46-47.

(5) Discussion and Findings. The record contains a number of different methods of estimating NIPSCO's cost of common equity. We recognize the cost of common equity cannot be precisely calculated and estimating it requires the use of judgment. Due to this lack of precision, the use of multiple methods is desirable because no single method will produce the most reasonable result under all conditions and circumstances.

In summary, the parties have presented evidence that the cost of equity could be as low as 7.1% and as high as 12.76%, and recommended a cost of common equity between 9.80% and 12.00%. Having considered the evidence of record and giving such weight to the evidence as we deem appropriate, we find that a cost of equity range of 9.90% to 10.50% is reasonable and appropriate for NIPSCO in today's economic climate. This is comparable with our cost of equity findings in Duke Energy Indiana's (formerly PSI Energy, Inc., hereinafter referenced as "PSI") most recent rate case in Cause No. 42359 (finding 10.5% to be appropriate), our approval of the settlement agreement in I&M's rate case in Cause No. 43306 (approving 10.5% as part of the settlement), and our approval of the settlement agreement in Vectren South's rate case in Cause No. 43111 (approving 10.4% as part of the settlement).

Having found an appropriate range, we now turn to determining a specific return to apply to NIPSCO's common equity. In our Order in Cause No. 42359 concerning PSI's rates, we recognized that a utility's operational and financial performance were appropriate considerations in determining a utility's cost of equity. The Commission has previously expressed concerns with the soundness of NIPSCO's managerial and operational decisions. For example, in Cause No. 42194, the Commission analyzed NIPSCO's plan to consolidate and close Local Operating Areas, or maintenance facilities, in its gas and electric service areas. The Commission questioned whether NIPSCO properly and thoroughly evaluated the impact of its plan on NIPSCO's ability to provide reasonably adequate service prior to the plan's implementation. Specifically, the Commission stated, "[T]he lack of any evidence on the part of NISPCO that demonstrates that it undertook a careful and thoughtful review of the [plan] vis-à-vis its possible impact on customers and service quality, has resulted in uncertainties regarding its implementation." *In Re: An Emergency Complaint Against N. Ind. Pub. Serv. Co.*, Cause No. 42194 at 56 (Aug. 10, 2005). As a result, the Commission found that NIPSCO should not implement its plan.

The Commission continues to have concerns regarding NIPSCO's managerial and operational decisions. To illustrate, in the present case, NIPSCO developed new tariff provisions without consulting its industrial customers—the customers who would be most affected by the new provisions and who comprise the majority of NIPSCO's load. While we have seen recent positive efforts by senior management to address customer and operational shortcomings, the Commission will continue to monitor and evaluate managerial efforts, and we will review and revisit those efforts in NIPSCO's next rate case.

Further, in Cause No. 42359, we determined that PSI's reliability and quality customer service warranted some consideration in our ultimate cost of equity determination. The evidence showed that PSI, and its parent Cinergy Corp., scored in the top quartile of the most recent J.D. Power and Associates customer satisfaction studies. In contrast, the evidence presented in this Cause demonstrated that NIPSCO was in the bottom quartile of the J.D. Power studies in 2007 and 2008, and one of the worst-rated utilities in 2009. While we are hesitant to place undue weight on customer surveys, the three-year trend of poor customer satisfaction cannot be ignored.

We must also consider the effect tracking mechanisms have in reducing risk in order to ensure that these reduced risks are properly reflected in NIPSCO's cost of equity. See Order, Cause No. 42359 at 53. NIPSCO has a number of trackers in place currently, and we have approved additional trackers in this Cause. No witness for NIPSCO addressed the effects of trackers on NIPSCO's cost of capital, which could be considered a fatal failing of its analysis.

The Commission has a unique role in regulating its jurisdictional utilities, which at times requires us to send a clear and direct message to utility management concerning the need for improvement in the provision of its utility service. Our determination of the authorized cost of common equity capital can be a very direct means to incent improved service. We anticipate that NIPSCO will respond accordingly and therefore anticipate that such authorized cost of common equity capital will apply for a limited duration as identified below.

Based on the entirety of the evidence at issue, and giving such weight to the evidence as we deem appropriate, we find that NIPSCO's cost of common equity capital shall be 9.9% and NIPSCO's overall weighted cost of capital to be 7.29%, determined as follows:

Description	Amount	Percent	Cost	Weighted Average Cost
Common Equity	$ 1,395,245,772	49.95%	9.90%	4.94%
Long-Term Debt	$ 906,631,137	32.46%	6.52%	2.12%
Customer Deposits	$ 63,684,199	2.28%	6.00%	0.14%
Deferred Income Taxes	$ 294,780,249	10.55%	0.00%	0.00%
Post-Retirement Liability	$ 102,637,766	3.67%	0.00%	0.00%
Post-1970 ITC	$ 30,350,460	1.09%	8.57%	0.09%
Totals	$ 2,793,329,583	100.00%		7.29%[8]

The cost rate we have assigned to the post-1970 investment tax credits is the overall weighted cost of investor-supplied capital determined as follows:

Description	Amount	Percent	Cost	Weighted Average Cost
Common Equity	$ 1,395,245,772	60.61%	9.90%	6.00%
Long-Term Debt	$ 906,631,137	39.39%	6.52%	2.57%
Totals	$ 2,301,876,909	100.00%		8.57%

This is consistent with the methodology adopted by the Commission in Indianapolis Power & Light Co., Cause No. 37837, p. 18 (Aug. 6, 1986). Applying the weighted cost of capital to NIPSCO's original cost rate base, we find a net operating income level for NIPSCO of $192,425,533 is just and reasonable.

The Commission recognizes that a 9.9% return reflects the low end of the range discussed above, and that a higher return may be appropriate if NIPSCO is able to demonstrate improved company performance in its next base rate proceeding. In order for NIPSCO's level of performance to be reevaluated by the Commission, NIPSCO is hereby directed to file a new base rate case with the Commission no later than September 30, 2012.

[8] In comparison, PSI Energy of Indiana's weighted cost of capital in Cause No. 42359 was 7.30%, while I&M's weighted cost of capital, based on settlement approved in Cause No. 43306, was 7.62%, and SIGECO's weighted cost of capital, based on settlement approved in Cause No. 43111, was 7.32%.

9. **Operating Income at Present Rates.**

A. **Undisputed Pro Forma Adjustments.** NIPSCO proposed a number of pro forma adjustments to its test year revenues and expenses that were accepted by the other parties. All the undisputed pro forma adjustments proposed by NIPSCO have been fully identified by the parties and are hereby accepted even though they may not be specifically discussed herein. The disputed adjustments are discussed hereinafter.

B. **Disputed Pro Forma Revenue Adjustments.**

(1) Credits and Discounts.

(a) Evidence. Pursuant to the settlement agreement in Cause No. 41746, NIPSCO's customers have been receiving bill credits of approximately $55 million per year. These bill credits will terminate upon the issuance of an Order by the Commission approving new base rates. Also, during the test year, many of NIPSCO's large industrial customers were receiving discounts pursuant to various Commission-approved special contracts, some of which have expired, others of which will expire six months following the implementation of new base rates in this proceeding, and others of which continue in effect until 2011 or later. Shambo Direct at 5. There was considerable disagreement over whether to adjust pro forma revenues at present rates to reflect the expiration of the bill credits and the expiration and/or imputation of industrial customer discounts. In its case-in-chief, NIPSCO proposed an adjustment to increase revenues at present rates by $80 million for expiring industrial customer discounted contracts. Miller Direct at 8; Shambo Direct at 5. NIPSCO did not make a present rates adjustment for the expiring bill credits in its direct case. However, NIPSCO did reflect this adjustment at present rates in its rebuttal filing.

The OUCC made an upward adjustment to present rate revenues of $55,102,044 to reflect the expiration of the bill credits. Catlin Direct at 7-8. IG made a comparable adjustment but in the amount of $57.8 million.[9] Gorman Direct at 3, 7, and 13. OUCC Witness Bolinger testified that NIPSCO's actual test year revenues fell far short of the amount that would result under full tariff rates such that pro forma revenues at present rates are understated and the calculation of the revenue increase overstated. Bolinger Direct at 5-7. Mr. Gorman took a similar position on behalf of IG. MU Witness Kerry A. Heid disagreed with their adjustments and took the position that the $55 million in bill credits were more appropriately addressed as an adjustment at proposed rates rather than present rates. Heid Cross-Answering at 19-21. The IG also added an additional adjustment to increase revenues by $107 million to reflect additional industrial customer discounts that were not captured by NIPSCO's $80 million adjustment. Gorman Direct at 3, 8, 16; Phillips Direct at 12.

On rebuttal, NIPSCO Witness Miller responded to these various contentions by pointing out that, other than with respect to mitigation, the characterization of these adjustments as adjustments at present or proposed rates makes no difference. She pointed out two facts to demonstrate her position. First, adjustments to revenues at present or proposed rates have no

[9] Mr. Gorman said he obtained this amount from Ms. Miller's proof of revenue. Ms. Miller testified Mr. Gorman's number was not correct and the actual test year bill credits amounted to $55,981,908. Miller Rebuttal at 14, 18. The bill credits actually received in any year will vary depending on customer usage. The settlement agreement in Cause No. 41746 provides that the bill credits actually received will be periodically trued-up to the agreed-upon amount of $55,102,044.

impact on the revenue requirement. The revenue requirement is the sum of the pro forma level of expenses plus the authorized return. Whether an adjustment is made at present or proposed rates only impacts the "starting point" for purposes of calculating the size of the increase/decrease needed to produce the revenue requirement. Miller Rebuttal at 11-12. Second, NIPSCO's proposed rates in this case have been designed to recover the revenue requirement with the assumption there would be no bill credits or contractual discounts in place after the Order in this case. Thus, for any period of time after rates are approved in this case during which contractual discounts remain in place, NIPSCO and not the ratepayers will absorb the shortfall. Ms. Miller demonstrated with an exhibit that the total revenue requirement would not change and the revenues that would be produced by the rates NIPSCO has proposed will remain the same regardless of whether these various adjustments for expiring bill credits and discounted contracts are treated as adjustments at present or proposed rates. *Id.* at 13-17, 20-21; Petitioner's Ex. LEM-R5.

With that background, Ms. Miller explained NIPSCO's rebuttal position with respect to these adjustments. NIPSCO adhered to its position that the proper approach is to treat the $55 million in bill credits as an adjustment at proposed rates because the bill credits will not cease until new rates are placed into effect as a result of this case. Ms. Miller explained, however, that to eliminate confusion associated with the various presentations, NIPSCO has re-presented its accounting schedules showing the adjustment as one at present rates. Miller Rebuttal at 18.

With respect to imputation associated with discounted contracts, Ms. Miller testified that NIPSCO included in its adjustment at present rates those customers whose contracts have expired or which, by their terms, will expire six months from the effective date of new rates in this case. Miller Rebuttal at 19, 24-25. She testified that, again, the only difference the various forms of treatment would make is with respect to mitigation and that, for those customers who will remain on discounted rates for six months after the Order in this proceeding, mitigation has already been built into their contracts via the six month grace period. *Id.* at 12, 24-25. For those customers, NIPSCO's shareholders will bear the shortfall for six months until those contracts expire and NIPSCO can charge them full tariff rates. *Id.* at 20. Mr. Shambo also confirmed there would be no cost shifting of the discounts to other customers under NIPSCO's proposed rates. Shambo Rebuttal at 9-10.

(b) Discussion and Findings. We find the treatment of the bill credits and special contract discounts as an adjustment at present or proposed rates makes no difference in the ultimate revenue requirement to be approved in this case. This is fundamentally true because, as discussed *infra*, we find that an equalized rate of return shall apply to the various rate classes, which elimates the need for any subsidy reduction scheme. While Mr. Phillips argued the present rates adjustment for industrial contract discounts should be increased by $107 million, he agreed his proposal "does not affect the calculation of the revenue requirement." Tr. at KK-21. Thus, the IG's proposed adjustment is not substantive, but does call attention to the magnitude of the benefit the industrial customers have received from their contractual discounts. To minimize differences among the parties, we will accept the $55 million bill credits adjustment as an adjustment at present rates as set forth in Mr. Miller's rebuttal exhibits. With respect to the special contract discounts, we approve NIPSCO's proposed $80 million adjustment at present rates.

(2) Off-System Sales.

(a) Evidence. In the test year, NIPSCO had $50,400,058 in revenue from OSS which, net of fuel costs, produced a margin of $29.1 million. Miller Direct at 9; Miller Rebuttal at 26-28. Consistent with its proposal to exclude OSS from base rates and to track OSS margins in its proposed Reliability Adjustment tracking mechanism ("RA Tracker"), NIPSCO removed the test year OSS revenue from its pro forma present rates revenues. Miller Direct at 11. NIPSCO also removed $21,285,492 of related OSS fuel expense. Miller Direct at 15. OUCC witness Mr. Satchwell stated that he was concerned with NIPSCO's OSS Margin Sharing mechanism because there is no amount built into base rates for OSS margins and recommended an amount of OSS margins be built into base rates, consistent with the Commission's final orders in Cause Nos. 42359 and 43111. Mr. Satchwell recommended that $8,731,000, the smallest margin achieved by NIPSCO for the calendar years 2002 through 2007, be used as the base rate amount because it is a reasonable amount and is not so high as to be unachievable. Satchwell Direct at 17. Mr. Satchwell agreed with Petitioner's recommendation to share above the base rate credit amount all OSS margins (80% with customers and 20% with the company). IG proposed a base rate credit for OSS margins of $15 million if the RA Tracker is not approved and $9 million if the RA Tracker is approved. Gorman Direct at 3, 8, 16; Dauphinais Direct at 3, 11, 19-20. LaPorte Witness Cearley said NIPSCO should include at least $11.9 million of OSS margins in base rates. Cearley Direct at 13.

In rebuttal, Mr. Shambo stated NIPSCO should not be at risk for OSS margins that may or may not be realized because the Midwest ISO now dispatches NIPSCO's generating units based on factors outside NIPSCO's control. He testified that NIPSCO's proposal aligns the interests of NIPSCO and its customers. On the other hand, the position of the OUCC and Intervenors would penalize NIPSCO for participating in the Midwest ISO even though that participation provides centralized dispatch benefits including reduced need for reserve margins, reduced transmission loading relief occurrences and downward pressure on wholesale prices. Shambo Rebuttal at 11-14. Ms. Miller testified the OUCC's and IG's margin adjustment is flawed because it ignores the revenue-based taxes and fees associated with OSS revenues. Miller Rebuttal at 27. She further pointed out OSS margins produced in prior years are not representative of future margin opportunities because of changed circumstances, including purchasing practices. She noted that NIPSCO's OSS margins during the period of January-April 2009 were $618,000 compared to $7.5 million in the same months in 2008. *Id.* at 27-28.

b. Discussion and Findings. We agree with the OUCC and Intervenors that it is appropriate to include an amount of OSS margins as a credit against base rates. In essence, this amount will serve as an offset to the Revenue Requirement otherwise determined in this case. This is consistent with our rulings in the most recent electric base rate cases, Cause Nos. 42359, 43111 and 43306.

With respect to determining an appropriate amount to include as an offset, we are mindful of Mr. Shambo's concerns that the amount of the offset should not be an amount that is not sustainable by NIPSCO. The OUCC recommended that the smallest annual margin amount achieved by NIPSCO during the past five years be used. We find that NIPSCO shall credit base rates by $8,731,000. As discussed *infra*, while we do not approve NIPSCO's proposed RA tracker, we do authorize NIPSCO to track OSS margins above the base rate credit amount with 50% credited to consumers and 50% to NIPSCO. This percentage of margin sharing is more consistent with the other electric IOU's that track OSS. We also find that in tracking such margins, NIPSCO may not apply a net annual margin of less than zero to the tracker, and all OSS net income shall be included as jurisdictional income for purposes of the FAC earnings test.

(3) Emission Allowance Sales.

a. Evidence. NIPSCO made an adjustment to remove \$11,790,599 of test year revenue generated through the sale of emission allowances. NIPSCO proposed that in the future when such sales arise, the net proceeds be passed back to customers via NIPSCO's existing Environmental Expense Recovery Mechanism ("EERM"). Miller Direct at 10. Phillip W. Pack, NIPSCO's Director, Generation Support Services and Major Projects, testified NIPSCO proposes to include in the EERM recovery of emission allowance purchase costs and the crediting of revenues from the sale of any emission allowances. Pack Direct at 11.

OUCC Witness Catlin rejected NIPSCO's adjustment and included the allowance sales proceeds in NIPSCO's going level revenues based on the testimony of OUCC Witness Cynthia M. Pruett, who opposed the tracking of emission allowance purchases and sales for reasons we shall discuss later in the section describing changes to the ECRM and EERM trackers. Catlin Direct at 10-11. Ms. Pruett showed that NIPSCO had earned revenues of \$10,762,552 in 2006, \$11,801,845 in 2007, and \$9,607,509 in 2008 from the sale of emission allowances. Prior to 2006, NIPSCO did not appear to sell or purchase any emission allowances. Pruett Direct 8. Ms. Pruett also testified that NIPSCO admitted to selling these allowances to fund the Company's ongoing capital needs. Ms. Pruett argued that NIPSCO sold off a significant number of zero-cost allowances to benefit the company's shareholders when these allowances should have been evaluated for future compliance with environmental regulations. Pruett Direct, 9-10. Because it appeared that NIPSCO acted irresponsibly with regards to selling zero-cost emission allowances, Ms. Pruett recommended Revenue Adjustment 9 (REV-9) be rejected and that the \$11.7 million emission allowance revenues be included as part of NIPSCO's test year revenues. Ms. Pruett also said the \$11.7 million in allowance sales revenue should be credited in base rates because "NIPSCO has charged ratepayers for its investment in [the environmental] projects" that made the allowance sales possible. Pruett Direct at 11-12.

In rebuttal, Mr. Pack testified NIPSCO is not expecting to make future sales of allowances, among other reasons, because of the impact of the Court decision overturning the Clean Air Interstate Rule ("CAIR") on the market for SO_2 allowances. *See North Carolina v. EPA*, 531 F.3d 896 (D.C. Cir. 2008) (per curiam); *North Carolina v. EPA*, 550 F.3d 1176 (D.C. Cir. 2008) (per curiam). He also stated Ms. Pruett was mistaken in believing the projects that gave rise to the sold allowances were included in NIPSCO's environmental tracker. He said the sold allowances resulted from SO_2 projects that have not been included in the tracker and for which NIPSCO is not presently recovering costs or earning a return on investment. Pack Rebuttal at 7-8.

Ms. Miller also testified in rebuttal that the OUCC and IG proposals were unreasonable because the level of emission sales during the test year is not ongoing, recurring or reflective of future operations. Miller Rebuttal at 29. As an alternative, Ms. Miller proposed that NIPSCO amortize the \$11.8 million amount as a base rate credit over a 5-year period (*i.e.*, \$2.3 million per year). *Id.* She proposed that at the end of the five-year period, NIPSCO will automatically terminate the credit by filing new tariffs, which would eliminate the impact of the amortization. *Id.* Ms. Miller also explained that, under NIPSCO's proposal, 100% of net revenues received from the sale of emission allowances and 100% of the costs associated with the purchase of emission allowances after the implementation of new base rates would flow through its environmental tracker. *Id.*

b. Discussion and Findings. We hereby approve NIPSCO's proposal to track emission allowance expenses and revenues via the EERM. However, rather than not including emission allowance revenues in test year revenues, we find that a portion of these revenues shall be included in test year revenues despite NIPSCO's assertion that future sales are unlikely. During both the test year and the pro forma year, NIPSCO generated a considerable amount of revenues associated with the sale of emission allowances. We cannot say that NIPSCO's interpretation of how CAIR is resolved constitutes a change that is fixed, known and measurable. While we note NIPSCO proposed to amortize its $11.8 million test year revenues over five years in its rebuttal case, we find that a shorter period is more appropriate, and order that NIPSCO shall amortize the $11.8 million in emission allowance revenues over three years as a base rate credit.

(4) Metal Melting Customers. NIPSCO adjusted revenue downward by $804,136 and associated fuel and purchased power expense downward by $628,813 to reflect the fact that during the test year certain customers in the metal melting business operated at levels above contract volumes and that this would not be permitted in the future. Miller Direct at 7-8, 11. OUCC Witness Catlin testified that this adjustment should not be made because these customers had also operated in excess of contract volumes in years prior to the test year. Catlin Direct at 9. Mr. Shambo testified in both direct and rebuttal that while these Rate 825 customers were allowed to exceed the limits on off-peak hours under the current tariff during the 2005-2008 period, that would not be the going-forward practice of the Company under its new tariff. Shambo Direct at 6; Shambo Rebuttal at 11.

The question is not what volumes have existed in the past, but what volumes will exist on a pro forma going forward basis. NIPSCO made the determination, during the test year, that these customers would no longer be permitted to operate in excess of contractual volumes. Accordingly, we find NIPSCO's adjustments to revenue and expense should be approved.

(5) Weather Normalization.

a. Evidence. NIPSCO made an adjustment to reduce revenue by $14,604,146 and fuel and purchased power expense by $3,683,450 to account for warmer than normal weather in the test year. Miller Direct at 7, 13. William Gresham, Manager of Forecasting for NCS, testified in support of NIPSCO's weather normalization adjustment. Mr. Gresham stated the Cooling Degree Days ("CDD") experienced in May through October of 2007 were 17% higher than the 30-year average period ended 2005 and should be normalized to reflect test year consumption under normal weather conditions. Gresham Direct at 3-4. Mr. Gresham noted that weather normalization of electric revenues is not new as NIPSCO has normalized for weather in two prior electric base rate cases (Cause No. 36689 and Cause No. 36394). *Id.* at 3. He used a base load/temperature-sensitive load normalization procedure—the same method accepted in the previous NIPSCO electric base rate cases. This methodology begins by identifying a base load of energy representing consumption for uses such as lighting and water heating, which are not temperature sensitive. The load in excess of the base load is then normalized for weather and added back to the base load to arrive at a normal level of usage. *Id.* at 6-8.

Mr. Gresham selected April as the base load month for most rate classes because April had the least amount of CDDs and the lowest level of kWh usage per customer during the year. Mr. Gresham used November, 2007 as the base month for residential heat pump customers because an unusually hot October during the test year impacted the use of heat pumps for heating and cooling of homes. Mr. Gresham normalized usage above the base load for the test year months of May through October. May and October were included because they each had an unusually high number of CDDs and the kWh usage per customer for those months was significantly above that for the base month. Mr. Gresham's weather normalization adjustment reduced sales volume in five and increased sales volume in one of the six months in the normalized season (May through October) producing a net 2.2% reduction of the annual sales volume. Gresham Direct at 8-10.

The OUCC accepted NIPSCO's weather normalization adjustment.

IG presented the testimony of Greg Meyer, consultant with Brubaker & Associates, Inc. Mr. Meyer accepted the claim that the weather in 2007 was warmer than normal, but believed the reduction to test year revenues should be much less than the level proposed by NIPSCO. IG Ex. 1 at 25. He testified that the May through October time period chosen by NIPSCO to weather normalize revenues for summer usage is too long to properly capture the effects of summer consumption patterns in NIPSCO's service territory and thereby the use of air conditioning. He also testified that the use of April as a base month is inconsistent with prior Commission decisions and is the lowest month of average electric usage for the entire year for some rate classes. *Id.* at 26.

Mr. Meyer testified that one should also look at the Heating Degree Days ("HDD") each month when determining the base month and measuring period. Mr. Meyer presented a comparative table showing the CDDs and HDDs based on a 30-year average of 1971-2000 temperature observations for the weather stations in South Bend, Indiana; Fort Wayne, Indiana; and Indiana Dunes, Indiana. *Id.* at 27. The table reflects that the months of April, May and October are predominantly heating months and are influenced most by heating degree days. The table also indicates that under normal circumstances in the NIPSCO service territory in the month of April, residential consumers are still engaging in home heating behavior indicative of a winter month, and do not begin to engage in summer-like home cooling behavior until May. Similarly, in October customers are typically refocused on heating their homes, and are no longer engaged in significant home cooling behavior. Therefore, Mr. Meyer testifies, NIPSCO is incorrect in assuming that the months of May and October involve temperatures that create air conditioning usage consistent with summer months.

Mr. Meyer also testified that the month of April has historically been the lowest average usage per month per NIPSCO Rate 811 residential customer for many years. IG Ex. 1 at 6. That residential class is the largest customer class of NIPSCO, and has the biggest impact on the use of air conditioning. By using April's low average usage as the base month, NIPSCO greatly increases the amount of variable electric usage attributed to summer weather. Mr. Meyer testified that using April data for determining the base usage understates the true level of base usage that exists in the residential class. *Id.* at 28.

Mr. Meyer provided a number of alternative calculations for comparative purposes to demonstrate that normalization of revenues is highly dependent upon the selection of the base period. IG Ex. 1 at 7. One alternative established a base usage using average consumption in the non-cooling months of January, February, March, November and December 2007, and applied that usage to the months of June through September, when NIPSCO's revenues are most affected by the use of air conditioning. This produced an adjustment which increases total revenues (including base charge for fuel expense) by $354,000. IG Ex. 1 at 1. In another example, Mr. Meyer used May as the base month and weather normalized sales for June through October, resulting in a revenue reduction of $4.1 million. IG Ex. 1 at 2.

In two other examples, Mr. Meyer used the weather normalization methodologies approved by the Commission in Cause Nos. 43111 and 36689. In the former proceeding, Vectren South weather normalized June through October using the average usage in May and October as the base load. This methodology results in a revenue reduction of $2,407,178. IG Ex. 1 at 3. In the latter proceeding, NIPSCO weather normalized June through September using May sales as a base load. This results in a revenue reduction of $1,814,470. IG Ex. 1 at 4. Mr. Meyer recommended that the Commission continue to apply this latter methodology from Cause No. 36689, resulting in an increase in margin revenues of $9.5 million. IG Ex.1. Thus, Mr. Meyer believes NIPSCO's proposed methodology results in an unreasonable and extreme adjustment when compared with previously approved methodologies (i.e. $14 million vs. $2 million).

Mr. Gresham submitted rebuttal testimony defending his use of April 2007 as the base month and his normalizing of May through October. He testified that Mr. Meyer's methodology required the Commission to draw conclusions about the appropriate inputs for weather normalization based on historic averages that mask the hotter than average temperatures actually experienced in May through October of 2007. Mr. Gresham disagreed with Mr. Meyer that April, 2007 could understate the true level of base usage absent some evidence of an event causing customers to not use lighting, water heating or other base load electrical appliances. Gresham Rebuttal at 2-4. No evidence of such an event was cited by Mr. Meyers.

Mr. Gresham also criticized Mr. Meyer's proposal to adopt a weather normalization procedure that blindly used the same base month regardless of the actual weather experienced. He noted that Mr. Meyer acknowledged that the presence of CDDs or HDDs is a factor to consider in establishing a base month. Mr. Gresham testified that May 2007 was much warmer than the average May and resulted in higher usage as evidenced by it having 100 CDDs and average usage of 612 kWh per residential customer compared to an average of 53 CDDs and 550 kWh per customer. Gresham Rebuttal at 4-5. Mr. Gresham testified that his decision to use April, 2007 as the base month was bolstered by Mr. Meyers' own data showing that the residential customer usage in April, 2007 of 548 kWh was more consistent with the average May usage from 2002 through 2006 of 550 kWh.

Mr. Gresham also disagreed with Mr. Meyer that May and October are predominantly heating months. Mr. Gresham stated these months were more aptly described as transition months when customers use both heating and cooling and that cooling has a more significant impact on load. To support this conclusion, Mr. Gresham cited NIPSCO data showing that only 6% of NIPSCO residential customers use electric appliances to heat their homes while 90% use electric appliances to cool their homes. Moreover, a regression analysis conducted by Mr. Gresham demonstrated that CDDs have a much greater impact on electric usage than HDDs during the months of May and October. Based on data for 2007, Mr. Gresham concluded that May and October were heavily influenced by CDDs and should be normalized. Gresham Rebuttal at 7-9.

(b) Discussion and Findings. In evaluating this issue it is helpful to first establish several points of agreement. NIPSCO and the Industrial Group are in agreement that base load consumption is the minimum amount that would occur each month if there was no weather related consumption, and that the base load is observed in the month with the least call for heating and cooling. They are also in agreement that the base load/temperature sensitive load normalization procedure is an appropriate method for adjusting kwh for ratemaking. Finally, both parties agree that 2007 was warmer than normal based on historical weather records.

We are faced, however, with competing interpretations of the effect of test year weather, measured in HDDs and CDDs, on kwh consumption by NISPCO customers. That issue determines the appropriate base month and weather normalization period to use in resolving the $9.5 million difference between NIPSCO's proposal and the adjustment recommended by the Industrial Group. IG Ex. 1 at 8. As a preliminary matter, we are skeptical that the use of 65 degrees as a threshold for measuring CDDs reflects actual consumer behavior.[10] For instance, NIPSCO's adjustment assumes that consumers in northern Indiana react to a 66 degree day in April by turning on their air conditioners. Pet. Ex. WG-1 at 5-6. We doubt that significant numbers of NIPSCO consumers engage in such behavior. Our doubts are supported by NIPSCO's request that those same customers conserve energy by turning down their home *heating* units to between 68 and 72 degrees. IG Ex. CX-50. However, in light of the historic use of 65 degrees as a threshold for establishing CDDs, we will adopt this methodology while giving it the limited evidentiary weight it merits. We would anticipate that in future cases, NIPSCO would present testimony in support of an appropriate threshold; testimony that would reconcile air conditioning use assumptions with energy efficiency program assumptions.

Mr. Gresham cites Exhibit GRM-6 in support of NIPSCO' claim that April had the least amount of weather-affected consumption, and therefore should be used as a base against which summer cooling behavior is measured. Pet. Ex. WG-R1 at 3. That exhibit reflects that April falls slightly below May as the month with the lowest average KWH use for Rate 811 customers. *Id.* Ergo, Mr. Gresham concludes, it had the least weather-related consumption. However, Mr. Gresham agreed that April would understate the true level of base usage if customers reduced electric load in April for reasons unrelated to weather. *Id.* at 3-4.

Based on weather records in NIPSCO's service territory, April 2007 had a combined total of approximately 550 HDDs and CDDs, while May had an approximate total of only 220 HDDs and CDDs. IG Ex. CX-47. That strongly suggests that May had far less weather related consumption than April. Moreover, April 2007 had approximately 540 HDDs compared with only 10 CDDs. *Id.* Thus, we agree with Mr. Meyer's testimony that April continued its historical trend of being a predominantly heating month influenced most by heating days, and under normal circumstances NIPSCO's northern Indiana residential customers are still engaging in home heating behavior indicative of a winter month. We also agree with Mr. Meyer that, based on the test year weather records, NIPSCO customers were not likely to engage in summer-like home cooling behavior until temperatures began to warm in late May. In fact, test year temperatures did not exceed a 65 degree average with any significance or regularity until the later days of May, and May 2007 had more HDDs (i.e. sub 65 degree average days) than CDDs. IG Ex. CX-47. Therefore, when identifying the month when NIPSCO customers are most likely

[10] Alternatively, the historic use of 65 degrees as a threshold for measuring heating behavior, or HDDs appears reasonably designed to reflect customer heating behavior.

to be using neither air conditioning nor heating – i.e. the month with the least "weather related consumption" – the evidence points to the transitional month of May, rather than the much colder month of April when customers are still engaged in winter-like heating behavior.

We agree that flexibility is necessary in selecting a month for base usage to avoid having weather itself impact a normalization adjustment, and that different methodologies must be used depending on the circumstances. However, there is no evidence on the record indicating that test year weather in this case differed in any material way from the test year NIPSCO used in Cause No. 36689, wherein weather was normalized June through September using May sales as a base load. Nor does NIPSCO explain why it is appropriate to use a relatively cooler month (April) to calculate summer base load in *northern* Indiana as compared with Cause No. 43111, in which the Commission approved the use of a warmer month average (May/Oct) to calculate summer base load. Likewise, NIPSCO does not explain why it is appropriate to use a relatively longer measuring period (May-October) in northern Indiana, and a shorter measuring period (June-October) as the measuring period in *southern* Indiana, where the weather is generally acknowledged to be warmer.

Based on the forgoing, we find that the methodology used in Cause No. 36689 remains the proper approach. Therefore, the month of May should be used as the base month because it more closely reflects the true level of base usage during non-summer months, and revenues should be weather normalized for the months of June through September, when air conditioning has the greatest impact. This results in a revenue reduction of $1,814,470, and an expense decrease for fuel of $408,324 as set forth on Exhibit GRM-8.

C. Depreciation Expense.

(1) Petitioner's Evidence. John J. Spanos, Vice President, Valuation and Rate Division of Gannett Fleming, Inc., testified in support of Petitioner's proposed new depreciation accrual rates and sponsored the depreciation study that he had conducted. He proposed new depreciation rates for all accounts and plants including common plant and Sugar Creek. Spanos Direct at 6-7. Ms. Miller used Mr. Spanos' proposed depreciation rates to determine NIPSCO's pro forma depreciation expense which resulted in a $21.048 million adjustment above the test year level.[11] Miller Direct at 29-30; Petitioner's Ex. LEM-2 (2nd Revised), p. 1, lines 54-55. Mr. Spanos explained that depreciation refers to the loss in service value that is not restored by current maintenance, incurred in connection with the consumption or prospective retirement of utility plant in the course of service from causes that can be reasonably anticipated or contemplated, against which the company is not protected by insurance. Spanos Direct at 7. Mr. Spanos conducted his study using the straight line remaining life method with the equal life group ("ELG") procedure. This method distributes the unrecovered costs of fixed capital assets over the estimated remaining useful life of each unit or group of assets. *Id.* at 9.

Mr. Spanos developed his proposed depreciation rates by first estimating the service life and net salvage characteristics for each depreciable group. He then calculated the composite remaining lives and annual depreciation accrual rates based on such service life and net salvage estimates. The service life and net salvage estimates were made by compiling historic data from records related to NIPSCO's plant, analyzing data to obtain historic trends of survivor and net

[11] This amount also includes a $227,322 adjustment resulting from a change in the allocation of common plant between the electric and gas operations implemented in the test year. Miller Direct at 29.

salvage characteristics, obtaining supplementary information from management and operating personnel, and interpreting the data. The historic data consisted of NIPSCO's accounting entries for the 72-year period from 1936 through 2007. Mr. Spanos used the retirement rate method for all electric and common accounts. This is an actuarial method of deriving survivor curves using the average rates at which each age group is retired. Mr. Spanos applied this method to each group of property and formed life tables which, when plotted, show original survivor curves for each property group. He then used Iowa-type survivor curves to interpret the original survivor curves. He explained that Iowa-type curves are widely used and are generalized survivor curves that contain the range of survivor characteristics usually experienced by utilities and other industrial companies. Field reviews were conducted to learn about Company operations, obtain an understanding of the function of the plant and obtain information about the reasons for past retirements and the expected causes of future retirements. Spanos Direct at 9-13.

Mr. Spanos also incorporated net salvage into his analysis. Net salvage is the salvage value received for an asset upon retirement minus the cost to retire the asset. When the cost to retire the asset (cost of removal) exceeds the salvage value, the result is negative net salvage. Because depreciation expense is the loss in service value of an asset during a defined period, it must include a ratable portion of both the original cost and net salvage. For most accounts, Mr. Spanos determined net salvage percentages by analyzing historical data. In the historical analysis, the net salvage, cost of removal and gross salvage amounts are expressed as percents of the original costs retired. Spanos Direct at 14-15.

For production plant, Mr. Spanos used the life span technique. Under this approach, the retirement date of the entire facility is estimated and interim survivor curves are used to describe the rate of retirement related to the replacement of elements of the facility that occur during its life. The estimated retirement dates for the production facilities were based on judgment and considered age, use, size, nature of construction, management outlook and typical life spans experienced and used by other electric utilities for similar facilities. Spanos Direct at 12-13.

Mr. Spanos determined the negative net salvage of the steam production plants by using dismantling cost estimates determined by Burns & McDonnell Engineering Co., Inc. ("BMcD") pursuant to site-specific demolition studies.[12] NIPSCO Witness Victor F. Ranalletta, Associate Engineer and Manager of the Energy Division in BMcD's Chicago Regional Office, sponsored the BMcD demolition cost studies for NIPSCO's fossil-fuel fired generating stations. <u>Petitioner's Ex. VFR-2</u> through <u>Petitioner's Ex. VFR-7</u>. In each of these studies, BMcD estimated the cost of demolishing the power block equipment and site facility and remediating the site. Each report describes the plant, sets forth the general cost assumptions used in the study, identifies costs not included in the study, explains how scrap metal value is determined and provides detailed cost estimates for demolition and remediation to both industrial condition and greenfield condition. Ranalletta Direct at 5. The industrial demolition cost estimates were based upon demolishing each plant down to the surrounding grade elevation, assuming all equipment and materials located above and below grade would be demolished and all below grade foundations would remain. *Id.* at 7. The greenfield estimates include the costs of removing all below grade foundations as well, filling the resulting below grade void, and remediation of ash ponds and coal yards. *Id.* at 8. A 20% contingency factor was included to

[12] The witnesses have used three different terms to refer to the removal of a retired generating unit and the remediation of the site – demolition, dismantlement and decommissioning. For purposes of this Order, we treat these terms as synonymous.

estimate costs that are presently unknown but which are expected to be incurred based upon past experience and uncertainty in the precision of the estimate. Mr. Ranalletta testified a 20% contingency was reasonable for estimating the demolition costs of NIPSCO's generating stations. *Id.* at 10-11. Because NIPSCO proposes to retire Michigan City Units 2 and 3 presently but leave the rest of the plant in service, BMcD prepared one estimate for Units 2 and 3 and a separate estimate for the building, Unit 12 and the balance of the plant.

Mr. Spanos escalated the BMcD industrial condition estimates for inflation at the rate of 3% per year to the anticipated date of final retirement. Because Mitchell and Michigan City Units 2 and 3 are to be retired in the very near future, Mr. Spanos assigned sufficient depreciation reserve to these units to account for the anticipated retirement and negative net salvage for these units so that the net book value will be zero. Spanos Direct at 15-16.

After determining service lives and net salvage characteristics for each group, Mr. Spanos calculated annual rates for each group using the straight line method, using remaining lives weighted consistently with the ELG procedure. Under this procedure, future book accruals for each vintage are divided by the composite remaining life for the surviving original cost of that vintage. For certain general plant accounts representing a very small portion of depreciable plant, Mr. Spanos' proposed depreciation rates were based upon amortization accounting in which the accrual is equal to the original cost multiplied by the ratio of the vintage's age to a defined amortization period. Amortization accounting was used for accounts with a large number of units of low asset value (such as furniture, computer equipment and tools) making it difficult to inventory the account. Spanos Direct at 17; Petitioner's Ex. JJS-2, p. 46-47.

Mr. Pack testified regarding the retirement of Mitchell (which has units that are 38 to 52 years old) and Michigan City Units 2 and 3 (which are 57 to 58 years old). Mr. Pack indicated that NIPSCO no longer intends to operate Mitchell as NIPSCO's 2007 Integrated Resource Plan suggested that restarting Mitchell should be abandoned in lieu of purchasing one or more combined-cycle gas turbines. Mr. Pack testified that NIPSCO intends to retire Mitchell, demolish the facilities and remediate the site to industrial condition. With respect to Michigan City Units 2 and 3, Mr. Pack stated that NIPSCO has determined the units are at the end of their useful lives due to extensive corrosion and wear due to their 50-plus years of service. Mr. Pack further stated that NIPSCO will retire Units 2 and 3 and demolish the facilities as described in the BMcD demolition studies but leave the building shell in place and continue to operate Unit 12. Pack Direct at 6-8.

(2) OUCC's Evidence. Michael J. Majoros, Jr. of Snavely, King, Majoros, O'Connor & Lee, Inc. testified on behalf of the OUCC. He testified that NIPSCO's present depreciation rates were approved in 1987 in Cause No. 38045 and reaffirmed in Cause No. 41746 in September, 2002. Mr. Majoros recommended approval of new depreciation accrual rates providing approximately $58 million less in annual expense than would result from NIPSCO's proposed accrual rates.

Mr. Majoros testified that the Commission should not allow any reflection of terminal decommissioning costs associated with Mitchell or Michigan City Units 2 and 3 in the calculation of depreciation accrual rates. His reasoning was that recovery of these costs forces a highly uneconomic and unnecessary cost onto ratepayers. He asserted that there was no payback associated with such an expenditure and demolition is unnecessary because NIPSCO has no legal obligation to demolish the plants. Majoros Direct at 13.

Mr. Majoros also disagreed with Mr. Spanos' use of the ELG procedure. He explained that the use of ELG in this case is a departure from the method under which NIPSCO's existing depreciation accrual rates were approved in 1987, which used the average life group procedure ("ALG"). Mr. Majoros explained that the ALG procedure applies a single average depreciation rate over the entire life of the account. Mr. Majoros acknowledged that the ELG procedure is more precise and that both ELG and ALG provide for the same full recovery, but he testified that the use of the ELG procedure requires annual depreciation rate changes and is more susceptible to errors resulting from forecasting inaccuracies than the ALG procedure. He then testified that if the ELG procedure is to be approved, it should only be applied prospectively to vintages after the date of Mr. Spanos' study, meaning the first ELG vintage would be 2008 for the purposes of the next depreciation study. Mr. Majoros claimed that to do otherwise would result in retroactive application of ELG. Mr. Majoros testified that this was consistent with application of the ELG procedure at the Federal Communications Commission ("FCC"). He testified that of his $58 million difference with Mr. Spanos, $24.1 million relates to his objection to Mr. Spanos' use of ELG. Majoros Direct at 15-20.

Mr. Majoros also objected to Mr. Spanos' cost of removal assumptions inherent in the net salvage percents. He explained that for generating plant accounts Mr. Spanos inflated the decommissioning estimates to the anticipated date of retirement. For mass property accounts, Mr. Spanos conducted a traditional net salvage analysis to which Mr. Majoros has been objecting for several years. He explained that these traditional methodologies increased the current estimates of future costs by projecting historic inflation into the future. Mr. Majoros restated all estimates of future dismantlement and retirement to present value. Mr. Majoros proposed that the annual depreciation rates should increase every year as the inflation is incurred. He presented an exhibit showing accruals for a single asset which he claimed demonstrated that Mr. Spanos' approach front-loads depreciation expense as compared to Mr. Majoros' approach. He testified that his own approach is more consistent with accrual accounting and matching. Majoros Direct at 21-25. He testified that his present value approach accounted for approximately $26 million of the $58 million difference with Mr. Spanos. Tr. at CC-10–CC-11.

Finally, Mr. Majoros testified that the Commission should "specifically recognize" that NIPSCO has a $892.7 million regulatory liability "for ratemaking and regulatory reporting purposes" of which $413.2 pertains to electric plant. Majoros Direct at 31, n. 38; 40. These amounts correspond to a regulatory liability recorded by NIPSCO for *financial reporting purposes* pursuant to Statement of Financial Accounting Standards No. 143 ("SFAS 143"). SFAS 143 requires that to the extent a public utility recovers through rates depreciation expense associated with future cost of removal that is not an asset retirement obligation ("ARO"), the amount should be recorded as a regulatory liability for financial reporting purposes only. *Id.* at 34-35. An ARO under SFAS 143 is a legal obligation that a party is required to settle as a result of an existing or enacted law, statute, ordinance, or written or oral contract or by legal construction of a contract under the doctrine of promissory estoppel. Tr. at CC-18. Mr. Majoros testified that without this treatment, NIPSCO and virtually all other utilities would consider the amounts recovered to be "their" money. He contended that if the Commission does not exercise authority in this area, these amounts would be unprotected and NIPSCO would eventually take these amounts into income, especially if in the future Generally Accepted Accounting Principles ("GAAP") accounting is replaced by international accounting standards. *Id.* at 36-39.

(3) IG's Evidence. James T. Selecky, a consultant with Brubaker & Associates, Inc., testified on behalf of IG. He proposed a number of changes to Mr. Spanos' depreciation study producing, collectively, an annual reduction in depreciation expense of $24.825 million from the level produced by NIPSCO's proposed depreciation rates. Selecky Direct at 4, 38. Unlike Mr. Majoros, he did not object to the use of ELG because this Commission has on several occasions expressed a preference for ELG. Id. at 7. He also did not discount to present value the net salvage assumptions. Id. at 20. Further, he did not propose to reallocate the portion of accumulated depreciation representing accruals of future cost of removal to a regulatory liability account as proposed by Mr. Majoros.

Mr. Selecky's first disagreement with Mr. Spanos' study concerned the 20% contingency factor included in the BMcD dismantling cost estimates. Mr. Selecky testified that NIPSCO did not include any offset to the dismantlement cost for the value of the land after dismantlement which he thought would be valuable to NIPSCO or an independent power producer as a site for a next generation power plant. In Mr. Selecky's opinion, current ratepayers, not future ratepayers, should get the benefit of this land value. Selecky Direct at 10-18. He recommended that the Commission "exclude the contingency factor from the dismantling studies to reflect the potential value of the site." *Id.* at 18. He also opined that the contingency factor does not represent a "real cost" and should have been applied to "direct costs, indirect costs and gross salvage or credits." *Id.* at 18-19.

Mr. Selecky's next change concerned inflation. Mr. Selecky reflected the impact of future inflation on the cost of dismantling the steam production units using a lower inflation rate (2.5% compared to 3% used by Mr. Spanos). He testified that current forecasts of future inflation over the next twenty years are closer to his projection than Mr. Spanos' projection. Finally, Mr. Selecky applied inflation to the net dismantling costs (i.e. net of salvage) and not just the gross dismantling costs. Selecky Direct at 3, 20-21.

Mr. Selecky reduced the accumulated depreciation allocated to Mitchell and Michigan City Units 2 and 3 by the amount of his reduction in the dismantling cost estimate for those facilities. He then allocated that amount to the other steam production units. The effect of this adjustment was to lower his proposed depreciation rates for steam production by $912,000 per year. Selecky Direct at 3, 23-25.

Mr. Selecky also reduced the depreciation reserve allocated to Mitchell by $52.589 million, his estimate of the Mitchell dismantling cost. The effect of this adjustment also was to increase the depreciation reserve allocated to the other plants and thereby reduce the depreciation rates for those plants. Mr. Selecky said he made this adjustment because, in his opinion, Mitchell was "retired prematurely." Mr. Selecky contrasted NIPSCO's proposed 60-year life span for its steam production units with the 53-, 50-, 50- and 39-year life spans of the four Mitchell steam units. He concluded that because the Mitchell units' life spans have been less than the estimated life spans used in the study for the other steam production plants, ratepayers have not received the fair value from the Mitchell plant. Therefore, Mr. Selecky opined, the Commission should exclude the Mitchell dismantlement cost from the Mitchell depreciation reserve. According to Mr. Selecky, his Mitchell adjustment reduces depreciation expense by $2.391 million per year. Selecky Direct at 3-4, 25-27.

Finally, Mr. Selecky objected to Mr. Spanos' net salvage percentages for transmission and distribution plant. He testified that Mr. Spanos' methodology has the effect of projecting past inflation into the future because it determines the net salvage ratio by dividing an annual net salvage expense in current dollars by the associated retirement in original cost dollars. According to Mr. Selecky, past inflation exceeds estimates of future inflation. He cited the same sources utilized for reducing the escalation rate for steam production plant dismantlement costs. He provided a hypothetical example involving a single asset that quantified an amount of removal costs that would be over accrued if future inflation were lower than historic inflation. IG Ex. JTS-8. Mr. Selecky contended that if this were to be true, intergenerational inequities would be created because the excess accrual would reduce future depreciation rates. Mr. Selecky reduced Mr. Spanos' net salvage ratios across-the-board by 30% based on a comparison of historical inflation over the last 30 years and his forecasted inflation rate of 2.5% per year. Mr. Selecky said this change would reduce transmission and distribution depreciation expense by $6.212 million per year. Selecky Direct at 27-38.

IG Witness Phillips concurred with Mr. Selecky that customers should not bear the Mitchell demolition costs in their rates. Mr. Phillips believed Mitchell's shut-down in 2002 resulted in NIPSCO's purchasing significantly more power. He said after the Mitchell shut-down, NIPSCO's FAC has increased 14.152 mills per kWh. Phillips Direct at 39-40. Mr. Phillips acknowledged on cross-examination that the FAC factor increase for Duke Energy, Inc. and Indianapolis Power & Light Co. was comparable to the increase NIPSCO experienced after Mitchell was taken off-line. Tr. at KK-26–KK-30. Mr. Phillips also contended that NIPSCO experienced significant O&M expense savings by ceasing to operate Mitchell which savings were not returned to the customers. Phillips Direct at 41.

(4) Petitioner's Rebuttal Evidence. Mr. Spanos offered rebuttal testimony to both Mr. Majoros and Mr. Selecky. With respect to ELG, Mr. Spanos explained that ELG is superior to ALG because it more correctly matches depreciation to the life of the asset. He explained that historically the use of ELG had been constrained by the large amount of computations that are required, but with advent of modern computer equipment, this constraint has been removed. Mr. Spanos stated that the ELG procedure has always been unquestionably more accurate and has been approved consistently by this Commission. He cited to a number of orders where we have accepted the use of the ELG procedure dating back to the initial approval in 1981 in Cause No. 36361 involving Citizens Gas & Coke Utility. Spanos Rebuttal at 5-10.

Mr. Spanos also disagreed with Mr. Majoros' position that ELG should only be implemented on a prospective basis. He explained that in both his study and Mr. Majoros' ALG presentation, the same amount of future accruals and remaining lives are used for determining annual depreciation. He said the question concerns the time period over which those accruals will be recovered. The use of ELG more accurately recovers future accruals related to each item over its actual remaining life rather than the use of averages for an entire account. Spanos Rebuttal at 11-12.

With respect to net salvage for plant other than steam production, Mr. Spanos explained that Mr. Majoros' proposal to discount net salvage to present value would constitute a radical departure from the accepted way of determining net salvage. He asserted that over the last five years, Mr. Majoros has proposed a variety of different ways to reduce net salvage, always with the same result of reducing depreciation expense. Mr. Spanos defended his approach as equitable, sound, supported by authoritative depreciation texts and well-accepted by regulatory commissions. He described Mr. Majoros' approach as an "annuity" or "sinking fund" method. Mr. Spanos provided an example to demonstrate how Mr. Majoros' approach backloads depreciation expense and leads to intergenerational inequity. According to Mr. Spanos, under Mr. Majoros' proposal depreciation rates would have to be changed every year to assure full recovery. Mr. Spanos explained that his methodology for computing net salvage is precisely the same traditional approach that was accepted by the Commission in the 2004 PSI Energy, Inc. Order in Cause No. 42359. Spanos Rebuttal p. 14-21.

Mr. Spanos responded to Mr. Selecky's proposal to reduce the transmission and distribution plant net salvage ratios by 30%. Mr. Spanos said Mr. Selecky's adjustment was arbitrary and departed from the traditional net salvage approach. He explained that inflation has been around for a long time and there is no reason to believe it will not continue for the foreseeable future. The inflation factor used by Mr. Spanos considers a long historical period containing both high growth years and low growth years, with many cycles. He said it would be inappropriate to disregard historic inflation based upon subjective predictions of future inflation which quite often prove to be incorrect. Mr. Spanos noted that his net salvage ratios are not limited to historical data but also reflect judgment, trends in removal practices and the age of the assets being retired. He emphasized again his net salvage method was precisely the same one approved in the 2004 PSI Order. Spanos Rebuttal at 26-28.

With respect to steam production plant, Mr. Spanos also cited the 2004 PSI Order for the proposition that future inflation should be included in the cost of removal estimate. Spanos Rebuttal at 29. With respect to Mr. Selecky's prediction of future inflation being at a lower rate (2.5%), Mr. Spanos noted that his 3% rate was more closely aligned with historic inflation over a long period and is the same escalation rate approved in the PSI Order. Mr. Spanos testified the 3% rate also is more consistent with construction cost trend indices than a basket of goods inflation index. He also explained that the reason why the escalation should only apply to the gross dismantlement cost (not the net cost) is that, in Mr. Spanos' experience, the cost of labor will continue to increase each year. He does not, however, see a corresponding increase of like magnitude for the value of the scrap that would be used as an offset. *Id.* at 30-31.

Mr. Spanos noted that the use of a contingency factor by Burns & McDonnell is a widely accepted approach and the 20% factor is comparable to that used by Sargent & Lundy in the dismantlement cost studies approved in 2004 PSI Order. As to the value of the site, Mr. Spanos testified that it is assumed the sites are being restored to industrial condition. In order to assume a marketable piece of real estate (for some use other than another production facility), the site would have to be restored to greenfield condition at a much higher cost. He noted that Mr. Selecky cited no orders supporting his position that either the value of the site must be estimated and used as an offset to the cost of removal or the contingency factor must be eliminated. Spanos Rebuttal at 33-35.

Finally, Mr. Spanos responded to the proposals of Mr. Selecky to disallow any recognition of the dismantlement cost of Mitchell and of Mr. Majoros to disregard the dismantlement cost of both Mitchell and Michigan City Units 2 and 3. Mr. Spanos testified that Mitchell was in operation for a very long time and it could not be said Mitchell was retired prematurely. Mr. Selecky's opinion was based solely on the comparison of Mitchell's age to the estimated life spans for other units. Whenever an average is used as comparison, there will be units across the United States shut down after the average number of years and some shut down before the average age. Mr. Spanos said consideration of the cost of removal related to Mitchell and Michigan City Units 2 and 3 is necessary to fulfill the purpose of depreciation rates to systematically and rationally recover the full service value of all of the utility's assets -- both their original cost and negative net salvage. Spanos Rebuttal at 35-36.

Alan Felsenthal, a Certified Public Accountant and a Managing Director of Huron Consulting Group, testified in rebuttal to Mr. Majoros. Mr. Felsenthal objected to Mr. Majoros' proposal to restate future net salvage to present value. He testified that Mr. Majoros' present value approach utilizes what is in effect a sinking fund, annuity or discount approach. Mr. Felsenthal testified that such an approach is contrary to the appropriate, traditional and widely accepted regulatory approach of recovering estimated future cost of removal on a straight line basis through depreciation accruals. Mr. Felsenthal stated Mr. Majoros' discounting methodology would result in ever-increasing annual charges which would back-load recovery to the detriment of future customers. Furthermore, when the rate base impact of Mr. Majoros' proposal is considered, long run revenue requirements are actually greater under Mr. Majoros' present value approach. This is because there is less accumulated depreciation to offset rate base. Felsenthal Rebuttal at 13-17; <u>Petitioner's Ex. ADF-R3</u>.

Mr. Felsenthal rejected Mr. Majoros' position that GAAP does not provide for the recognition of future inflation in current periods. He testified that GAAP requires depreciation over the useful life of the assets in a systematic and rational manner (usually straight line). Depreciation accounting contemplates allocating the <u>net</u> original cost (original cost plus or minus future negative and positive salvage). The regulatory rationale is to promote intergenerational equity and appropriately match the cost to the provision of service. Mr. Felsenthal said NIPSCO's approach to net salvage is used by virtually every enterprise under GAAP. He stated Mr. Majoros' sinking fund or annuity approach, which results in ever-increasing charges for depreciation, is not consistent with GAAP, citing SFAS 92 which states "annuity methods of depreciation are not acceptable under generally accepted accounting principles applicable to enterprises in general." Felsenthal Rebuttal at 9-17.

Mr. Felsenthal also explained why recognition for regulatory purposes of the regulatory liability reflected for financial reporting purposes would be inappropriate and unnecessary. He testified that the showing of accumulated cost of removal as a regulatory liability for financial reporting purposes is a recommendation of the SEC, not a requirement of the Financial Accounting Standards Board ("FASB") or GAAP. Furthermore, no support exists for recording these amounts as a regulatory liability for ratemaking purposes. He explained that under the FERC Uniform System of Accounts ("USOA"), NIPSCO is not permitted (without regulatory approval) to remove amounts previously accrued for removal costs from accumulated depreciation and record them in income or apply them to some other account. He explained that the ARO referenced in SFAS 143 corresponds to retirement obligations for which there exists a present legal obligation (such as those that relate to PCBs and asbestos). Other obligations may arise and become AROs in the future and other removals may never be legally required but are nevertheless implemented for other reasons such as safety. He testified that SFAS 143 does not require that AROs for financial reporting purposes be removed from accumulated depreciation for regulatory purposes. Felsenthal Rebuttal at 20-29. Mr. Felsenthal also testified that in FERC Order No. 631, FERC concluded there was no reason to change regulatory accounting for non-legal costs of removal, although utilities are required to maintain subsidiary records that identify the cost of removal in the depreciation accruals. *Id.* at 40.

NIPSCO Witness Bradley K. Sweet, NIPSCO's Vice President, Strategic Planning and Operations Support, responded to assertions that NIPSCO's depreciation rates should not recover the dismantlement costs for Mitchell and Michigan City Units 2 and 3. Mr. Sweet disagreed with OUCC Witness Majoros' contention that these costs are uneconomic and unnecessary. He also discussed the shutdown, retirement, and demolition of Mitchell.

Mr. Sweet stated the shutdown of Mitchell Units 4, 5, 6 and 11 occurred in January of 2002 because an economic slowdown rendered the energy unnecessary, the cost of maintaining the units was substantial and NIPSCO's remaining generation resources were adequate to satisfy NIPSCO's projected demand through 2003. Sweet Rebuttal at 9. He said NIPSCO intended to restart the Mitchell facility, but the City of Gary, Indiana ("Gary") announced plans to acquire Mitchell in 2004 and initiated a proceeding with the Commission to condemn the facility. Sweet Rebuttal at 7. Mr. Sweet indicated that NIPSCO requested an expedited procedural schedule to quickly resolve Gary's petition because failure to restart Mitchell in 2004 would increase the probability that a new source review permit would be required. However, an expedited schedule was opposed by some parties. *Id.* at 7-8. Because of the potential for Gary to acquire the Mitchell site, Mr. Sweet testified that NIPSCO maintained the facility in a mothballed state rather than incurring the substantial cost of restarting it. Sweet Rebuttal at 9-10. In January, 2006 the Commission rejected a settlement agreement between NIPSCO and Gary. *Id.*

Mr. Sweet described the ensuing stakeholder process used to discuss Mitchell's future. NIPSCO and LaPorte both commissioned studies to evaluate the cost of restarting Mitchell. NIPSCO's study assumed new source review would be required to restart Mitchell and estimated the cost at between $587 million and $758 million. LaPorte's study did not assume new source review and projected a much lower restart cost. Mr. Sweet explained that Indiana Department of Environmental Management ("IDEM") subsequently confirmed new source review would be required. Sweet Rebuttal at 10; Petitioner's Ex. BKS-2. NIPSCO evaluated alternative energy sources and concluded that there were more cost effective options for satisfying its capacity needs.

Mr. Sweet also noted that NIPSCO was not alone in retiring coal plants of Mitchell's vintage. Using data from the Energy Information Administration, he provided a list of more than 40 coal generation units placed into service in the 1950s and 1960s which have been retired. He concluded that changing environmental requirements and system demands have changed the value placed on older, less efficient coal facilities like Mitchell. Sweet Rebuttal at 11-14.

Mr. Sweet said that a utility cannot simply walk away from a facility that is no longer being used to provide service and abandon it in place because this creates other issues. Mr. Sweet explained utilities would continue to incur costs for abandoned facilities to maintain the sites in a safe and secure condition. Mr. Sweet testified that NIPSCO would prefer not to abandon the plant and leave it to deteriorate, especially when the property on which it resides may be used for other purposes. Sweet Rebuttal at 8-9.

Based on this analysis, Mr. Sweet disagreed with Mr. Phillips' assertion that NIPSCO should be required to absorb the cost of demolishing Mitchell. Sweet Rebuttal at 14. Mr. Sweet did not dispute that NIPSCO avoided O&M costs associated with Mitchell, but he noted that these savings freed funds to cover other cost increases and generally did not inure to shareholders as evidenced by the fact that NIPSCO only rarely earned its authorized return. Sweet Rebuttal at 15. He concluded by noting that NIPSCO's customers benefited from many years of service from Mitchell and should pay the cost of demolishing the facility.

(5) Discussion and Findings.

(a) ELG v. ALG. We consider the debate between ELG and ALG to have already been resolved. This Commission has frequently and consistently expressed its preference for the use of the ELG procedure.[13] We have heard nothing new in this case to change our view and so approve the use of the ELG procedure in Mr. Spano's depreciation study.

The next issue raised is the application of the ELG procedure to existing vintages. Mr. Majoros contended ELG, if approved, should only apply on a going forward basis to plant not included in the current depreciation study. Mr. Majoros admitted that his position taken in this case is the same position taken by OUCC Witness Sarah J. Mamuska in *Indiana-American Water Co.*, Cause No. 40703 (Dec. 11, 1997). Tr. at CC-10. There we explained her position:

> Ms. Mamuska contended the ELG procedure was front loaded and that application of the ELG procedure to embedded plant would be retroactive ratemaking because it would result in a depreciation shortfall which "must be borne by current and future customers" since it cannot be charged to previous customers. She cited the FCC as having implemented the ELG procedure on a going-forward basis.

Indiana-American, p. 47. In *Indiana-American* we rejected Ms. Mamuska's position (the same position Mr. Majoros takes here), finding:

> We do not agree that application of ELG to embedded plant would be retroactive ratemaking. Under any method the current undepreciated balance of the property in each account would be recovered prospectively. . . . Accordingly, we reject the OUCC's proposal to implement ELG only for property placed in service after 1995. . . . Nor can we agree with the OUCC's contention that the ELG procedure "front loads" depreciation accruals. As we stated in the *Public Service Co.* Order [in Cause Nos. 37414-S2 and 38809], "[t]he ELG procedure remains a straight-line procedure . . . and does not permit the recovery of large amounts of capital of a particular asset in the earlier years of its life." 112 PUR 4th at 146. We explained that "whether the speed of capital recovery under the ELG procedure is quicker or slower than under the ALG procedure is really a function of the life of the asset, as it should be."

Id., pp. 49-50. Mr. Majoros added nothing that we have not already considered concerning the use of the ELG procedure with respect to embedded plant. For the reasons given in *Indiana-American,* we reject Mr. Majoros' arguments.

(b) Future Inflation. OUCC Witness Majoros objects to the inclusion of future inflation associated with costs of removal. On cross-examination Mr. Majoros admitted that both he and Mr. Selecky had testified in *PSI Energy, Inc.*, Cause No. 42359 (May 18, 2004), that future dismantlement costs and net salvage costs should be stated at net present value. Tr. at CC-11. In that case, we found:

[13] *See, e.g.*, *Ind.-Am. Water Co.*, Cause No. 43081, at 2 (Nov. 21, 2006); *PSI Energy, Inc.*, Cause No. 42359, at 72 (May 18, 2004) ("This Commission on numerous occasions has accepted the use of the ELG methodology").

> The final issue regarding dismantlement costs is whether inflation should be factored into the dismantlement cost estimates to be utilized in determining PSI's depreciation rates. Mr. Selecky and Mr. Majoros objected to the use of inflation. Mr. Spanos utilized Mr. Wendorf's dismantlement costs which are stated in 2002 dollars, and factored inflation up to the year of the projected dismantlement as a factor in his consideration, along with his analysis of historical, or interim retirements. We find Mr. Spanos' approach to be realistic and consistent with past experience. Inflation has been a fact of life in the American economy for many years. Not factoring inflation into dismantlement costs to be incurred in the future would understate those costs, with the result being that future customers would have to pay costs arising from facilities that are not serving them. This result flies in the face of matching rates with costs incurred for service, a sound ratemaking principle followed by this Commission. Moreover, current customers receive benefit by factoring in inflation, as it may appropriately allow for a reduction in rate base because of the increased accumulated reserve for depreciation. Accordingly, this Commission finds that accounting for inflation in determining the dismantlement estimates to be used as a part of PSI's depreciation rates is reasonable.

PSI Energy, Inc., p. 71. As with ELG, Mr. Majoros has provided no new or additional evidence suggesting a change from our past practice is warranted. Accordingly, we reject Mr. Majoros' proposal to restate costs of removal at the present value.

The only other objection made about inflation was from Mr. Selecky who objected to the rate of inflation assumed for steam production plant and the net salvage ratios for all other accounts. Based upon projections of future inflation set forth in Annual Energy Outlook and Blue Chip Economic Indicator, Mr. Selecky reduced Mr. Spanos' recommended depreciation accrual rates by assuming that future inflation will be lower than historical inflation.

It is noteworthy that one of the sources upon which Mr. Selecky relies cautions against relying upon such long-range projections of future inflation. Blue Chip Economic Indicator warns: "Apply these projections cautiously. For the most part economic and political forces cannot be evaluated over such long time spans." Petitioner's Ex. CX-3, p. 14. Annual Energy Outlook specifically notes that its 2008 projections relied on by Mr. Selecky predated the federal deficits incurred as a result of the American Recovery and Reinvestment Act of 2009. Petitioner's Ex. CX-4. More recent projections factoring those impacts show higher inflation projections than those on which Mr. Selecky relies. *Id.* Mr. Selecky cites net salvage practices of certain other commissions (Selecky Direct at 29-30), but they do not appear to address the inflation adjustment that Mr. Selecky proposes here. We further note that while Mr. Selecky's colleague at Brubaker & Associates, Mr. Meyer, asks the Commission to rely on lead lag studies prepared by the staff of the Missouri Commission (Meyer Direct at 46-47), that Commission has recently rejected a proposal made by Mr. Selecky to use a forecasted 2.5% inflation rate to determine future net salvage, stating:

> Even more fundamentally, MIEC and Public Counsel have failed to demonstrate any reason to believe their estimates of future inflation are a more reliable predictor of future inflation than the past history used by Staff and AmerenUE in their calculations. Expert predictions of future inflation can be little more than

> guesswork. It is impossible to accurately predict what inflation might occur 30 to 40 years in the future. No doubt if an esteemed panel of experts had been polled in 1960 they never would have predicted the severe inflation of the 1970s and 1980s. Similarly, today's experts cannot possibly foresee whatever inflation may occur in 2023. The Commission finds past history to be a better predictor of future inflation for ratemaking purposes.

Union Elec. Co. d/b/a AmerenUE, 2007 Mo. PSC LEXIS 716 at *153-154, 257 PUR4th 259, 304 (May 22, 2007).

We understand there are different viewpoints on an appropriate rate of future inflation but take comfort in the fact that Mr. Spanos' study relies upon long periods covering multiple business cycles. We note that OUCC Witness Majoros measured future inflation for his present value adjustment based on the historical period of 1984 to 2007, resulting in inflation factors even higher than what Mr. Spanos used. Majoros Direct at 30; Public's Ex. MJM-9, Sch. 3, Col. (3). We find that historical experience is a better indicator of the future than admittedly less reliable projections about future inflation. We therefore reject Mr. Selecky's proposals to modify the depreciation rates using lower estimates of future inflation based upon the hypothesis that long run future inflation will be lower than in the past.

(c) Mitchell and Michigan City Decommissioning Costs. The IG and OUCC both proposed to exclude the cost to dismantle certain facilities from NIPSCO's depreciation rates. The OUCC asserts dismantlement of both Mitchell and the Michigan City Units 2 and 3 should be excluded because dismantlement costs are uneconomical and unnecessary. IG proposes to exclude the Mitchell dismantlement costs because Mitchell was prematurely retired. For the reasons described below, we find that decommissioning costs for these units shall not be included in Petitioner's proposed depreciation expense.

It is axiomatic that only used and useful plant can be depreciated. Once plant is no longer used and useful, that plant is removed from rate base and the accompanying depreciation expense is also eliminated. Here, it is undisputed that Mitchell and Michigan City 2 and 3 were not included by Petitioner in Petitioner's proposed rate base, and as discussed above, the Commission determined the value of rate base excluding those units. Based on that exclusion, we find that those decommissioning costs shall not be included in Petitioner's depreciation rates. Accordingly, we need not address any of the IG or OUCC arguments on this issue. To the extent NIPSCO incurs decommissioning costs for these units in the future, our decision here with respect to depreciation rates does not preclude NIPSCO from seeking to recover those cost in a subsequent rate proceeding.

(d) Remaining Issues. The next issue to be resolved is the use of a contingency in the BMcD dismantlement studies. Mr. Selecky argued either the post-remediation value of the land in industrial condition should be an offset to the dismantlement costs or the contingency should be eliminated as a trade-off for the value of the land. Mr. Selecky did not identify the dollar value of the land after dismantlement. As a result, there is no evidence in the record to guide us in determining whether this would produce a material difference in the depreciation rates or be a reasonable trade-off for the contingency, assuming for the sake of argument it would even be proper to treat a non-depreciable asset like land as salvage. Further, we find it noteworthy that Mr. Selecky is not a licensed real estate appraiser. As a result, the record is devoid of any evidence to judge whether his proposal to equate the value of the land with the contingency is reasonable. We also give weight to the fact that the 20% contingency factor used in the BMcD demolition cost studies is conservative compared to the 25% contingency factor we accepted in PSI Energy, Inc., Cause No. 42359, at 70-71. Also, the assumption that the sites will be remediated to industrial condition, rather than greenfield condition, is also conservative. Id. at 70. No evidence was presented that this Commission has ever used the value of land as an offset to an asset's cost of removal. In fact, Mr. Selecky did not identify to us any decision of any regulatory commission accepting his position regarding land and the contingency. Petitioner's Ex. JJS-R5; Petitioner's Ex. JJS-R6. Given that Mr. Selecky's recommendation would be such a departure from our past practice and that we have scant evidence to guide us in this exercise, we reject Mr. Selecky's proposal.

The next issue raised by Mr. Selecky concerns the application of escalation to the gross cost of salvage rather than net cost. As with contingency, Mr. Selecky has not offered the impact that this proposed change would have and whether it would be material. We are persuaded by Mr. Spanos' testimony that the charges most likely to be impacted by future inflation are labor rather than the salvage components. Also, as mentioned above, the contingency factor in the BMcD demolition studies and the industrial condition assumption in Mr. Spanos' depreciation study are conservative. Accordingly, we reject Mr. Selecky's argument.

Finally, there is the issue of SFAS 143 and Mr. Majoros' request that we require the cost of removal reflected in NIPSCO's depreciation reserve to be reclassified as a regulatory liability. First, we see little difference in Mr. Majoros' proposal here and the one he made in the 2004 PSI Energy, Inc. rate case that we did not accept. *PSI Energy, Inc.*, Cause No. 42359 at 62. Second, we are left to ponder why it would be important for us to do as Mr. Majoros recommends. The only basis that we have heard is that without such recognition, NIPSCO will be inclined to move these amounts to income. But NIPSCO cannot unilaterally make that decision. The USOA provides: "The utility is restricted in its use of the accumulated provision for depreciation to the purposes set forth above. It shall not transfer any portion of this account to retained earnings or make any other use thereof without authorization by the Commission." USOA, Electric Plant Account 108(E); 170 I.A.C. 4-2-1.1(a). Accordingly, we find Mr. Majoros' recommendation should not be accepted.

(e) Ultimate Finding. For the foregoing reasons, we find that Mr. Spanos' depreciation study and proposed depreciation accrual rates for electric and common plant as set forth in Petitioner's Exhibit JJS-2, pp. 51-62, are hereby approved, with the exception of decommissioning costs. This results in a total increase in depreciation expense to reflect the new rates, Sugar Creek, and common plant of $17,744,442. As proposed by NIPSCO (Hershberger Direct at 25), NIPSCO shall determine the depreciation and amortization expense associated with Sugar Creek by applying the rates set forth in Petitioner's Exhibit JJS-2, p. 60, to the acquisition price of the plant.

D. Operation and Maintenance Expense.

(1) Labor Cost Adjustments.

(a) Petitioner's Evidence. NIPSCO Witness Eileen O'Neill Odum described the reorganization within NIPSCO intended to improve NIPSCO's focus by providing needed support in a variety of substantive areas including regulatory compliance, system reliability, and customer satisfaction. Odum Direct at 4-5. She testified that she had authorized the creation of 83 new staff positions in 2008 to effectuate that reorganization and the furtherance of NIPSCO's performance. Ms. Miller sponsored proposed Adjustment OM-9 to increase test year operation and maintenance expenses by $6.4 million to reflect the new positions.

NIPSCO also presented testimony from Robert D. Campbell, Senior Vice President of Human Resources for NiSource, Inc., that addressed NIPSCO's compensation and benefits practices in support of NIPSCO's test year labor expense as well as several pro forma adjustments. Mr. Campbell testified that NiSource, NCS, and NIPSCO utilize a "total rewards" compensation philosophy that considers all forms of compensation in order to attract and retain qualified employees. He explained that employee compensation generally consists of three components: base pay, annual incentive opportunity, and benefits. Campbell Direct at 3-4.

Mr. Campbell testified that NCS has regularly retained Hewitt Associates, a global human resources consulting firm, to assist in the setting of competitive salary ranges, establishing a program for administering salary increases, and evaluating and recommending modifications to NIPSCO's wage and benefit plans. He explained that Hewitt is familiar with the NiSource, NCS, and NIPSCO information systems, data, personnel and corporate structure based on its long-term relationship. He testified that Hewitt has helped with the implementation of a base pay management system and has also assisted in the measuring of benefit programs. Mr. Campbell testified that NIPSCO's compensation packages are reasonable and competitive. Campbell Direct at 4-5.

Mr. Campbell explained that the terms of NIPSCO's two collective bargaining agreements determine wages for its union employees and those agreements provide for wage increases of 3.0% effective at the conclusion of the years ending December 31, 2007 and December 31, 2008. He testified that for employees not covered by those contracts, base pay is determined using market data to establish a compensation range of between 75% and 125% of the market median, with specific decisions within that range based on the skill set, experience and performance of the employee. He testified that effective March 1, 2008 an overall average 3.25% pay increase was awarded to NIPSCO's non-union workforce. Campbell Direct at 6-7.

Mr. Campbell detailed NIPSCO's incentive compensation plan in his direct testimony. He testified that the incentive compensation plan is intended to drive the Company's goals through documented performance in four key areas: Customer, Employee, Financial, and Process/Capability. He testified that the potential to earn incentive pay is necessary to attract and retain qualified employees as part of a total compensation package, and noted that by 2007 nearly 90% of U.S. companies had implemented a broad-based variable pay plan. Campbell Direct at 7-8.

Mr. Campbell explained that NIPSCO's incentive levels and ranges are established by placing each employee in a job scope level based upon his or her responsibility in the organization, with an incentive range that corresponds to the assigned job scope. The incentive range defines the opportunity for an incentive payout that begins at a "trigger" level and increases through a "target" level to a maximum "stretch" incentive. Percentages over base pay are then assigned to each of the three levels for each job scope. Mr. Campbell testified that if specific financial goals are met, an incentive pool is created for distribution to employees. For non-exempt employees, the incentive payout is determined by multiplying eligible wages for the employee times the incentive payout percentage. For exempt (non-union) employees, one third of the incentive payout is determined through the same calculation, with the remainder determined through an assessment of the employee's success against defined individual performance objectives. Mr. Campbell testified that payment of incentives is based on whether the established criteria have been met, and that NIPSCO had paid incentives at some level in three of the past four years. Campbell Direct at 8-10.

Mr. Campbell testified that NIPSCO's base salary and total cash compensation are reasonable and competitive. Campbell Direct at 12. Mr. Campbell's conclusion was supported by an analysis that compared base salaries and incentive pay for a sampling of NIPSCO positions to similar external positions based on data provided by Hewitt. *Id.* at 11. The comparison showed that base salary for the NIPSCO positions sampled was 4.6% below the comparable market positions and that total cash compensation was 7.4% below the market. *Id.* at 11-12; Petitioner's Ex. RDC-4. He also testified that similar conditions exist for NCS, with base salaries 3.2% below the market and total cash compensation 3.9% below. *Id.* at 12; Petitioner's Ex. RDC-5.

Mr. Campbell testified that merit increases of 2.5% for its non-exempt, non-union employees and of 3.0% for its exempt employees were below average for both companies within the region and within the utility industry. Campbell Direct at 13; Petitioner's Ex. RDC-6. He explained that the merit increases for non-exempt employees took effect March 1 of each year. Mr. Campbell testified that regular merit increases are important to recognize employee contributions and to attract a high quality workforce and are therefore awarded on a regular basis. *Id.* at 13-14.

Mr. Campbell's testimony also addressed the benefits paid to NIPSCO's employees, including health and welfare plans, a defined benefit plan (pension), a 401k plan as well as paid time off for vacation, holidays and sick days. He testified that pension plans are provided to certain NCS and NIPSCO employees under one of four pension offerings. He explained each of the four offerings (the Account Balance 2011 formula, the Account Balance formula, the salaried/non-exempt Final Average Pay formula, and the bargaining unit Final Average Pay formula) as well as the way benefits are calculated for each. Campbell Direct at 14-16. He also explained that NIPSCO's retirement savings plan and bargaining unit deferred savings plan allow employees to contribute 1% to 50% of eligible compensation on a pre-tax basis, and that contributions are matched by NIPSCO at a rate determined based upon the pension plan in which the employee participates. *Id.* at 16-17.

Mr. Campbell testified that medical plans are provided to employees pursuant to four self-insured plans, and also provided to retirees who meet certain criteria. Campbell Direct at 17. He also explained NIPSCO's three dental coverage options, its vision plan, its three forms of life insurance, its long term disability plan, and its employee assistance program, each of which are available to employees. *Id.* at 18-19. Mr. Campbell testified that NIPSCO's health plans are competitively bid to ensure that both carriers and third-party administrators are able to provide quality service in the most cost-efficient manner. *Id.* at 19. He testified that NCS, on behalf of NIPSCO, is proactive in examining ways to better manage health care costs. He explained that underwriting margins are reduced because primary plans are self-insured. He noted NIPSCO's affiliation with NiSource ensures that NIPSCO is in a position to take advantage of greater purchasing power and a larger risk pool. *Id.* at 20. Mr. Campbell explained that NIPSCO's employees have experienced increases in their contributions toward health plans because they share on a percentage of cost basis.

Mr. Campbell testified that NCS performs periodic studies to compare NIPSCO's benefits to a "market basket" of similar offerings from other energy industry and non-energy industry employers. The total value and the employer-paid portion of the package are rated on a standardized value scale to assess the deviation of the NIPSCO standard benefit offerings from the average of other companies. NCS and Hewitt also conduct ongoing evaluations of marketplace trends in benefits and other ways to reduce the cost of providing the necessary benefits. He testified that Hewitt's most recent study showed that the employer-paid value of its benefits plan was 0.1% higher than the average of the selected industry cohort. He concluded that NIPSCO's benefits are competitive and reasonable when compared with those offered by other similar employers. Campbell Direct at 21-22.

Mr. Campbell testified that the utility industry is faced with a significant challenge posed by the aging of its workforce. He explained that projected retirements over the next five-years will require the filling of certain critical positions ahead of time to allow for formal and on-the-job training. He testified that the median age of all NIPSCO electric-related employees as of the close of the test year was 50.0 years -- considerably higher than the rest of the electric utility industry and the U.S. workforce in general. Campbell Direct at 23-24.

Mr. Campbell testified that the eligible retirement age bracket for NIPSCO begins at 55 years of age as a function of NIPSCO's pension and its collective bargaining contracts, and that at the end of 2007 about 26% of NIPSCO's electric associated workforce was in that age bracket, and 51% of that workforce is over the age of 50. He testified that as a result of those facts, over half of NIPSCO's electric-associated workforce will be eligible for retirement by 2012. Campbell Direct at 24-25.

According to Mr. Campbell, 64% of the 830 electric employees eligible for reduced-benefit or full retirement over the next five-years will choose to retire by the end of 2012, based on statistical projections included in his testimony. Campbell Direct at 25-26. He testified that NIPSCO has identified positions within its bargaining unit employees in generation, transmission, and distribution that are especially critical to safe, reliable and effective day-to-day operations, along with "feeder" positions into those critical jobs. He explained that over the past five-years NIPSCO has focused on the timely filling of retirement vacancies into the critical and feeder positions. *Id.* at 27.

Mr. Campbell testified that NIPSCO has taken steps to manage the acceleration of retirements. He explained the "mega-bid" process used by NIPSCO whereby a job-needs complement is developed for the upcoming year based upon analysis of retirement trends and employee migration. Bids are posted for this projection in January and filled as required by the timing of retirements to streamline the creation of an applicant pool and to allow for certain positions to be filled in advance to allow for extra training. Campbell Direct at 27. He added that succession planning programs have helped accomplish a critical-position focus, and that the hiring of summer interns and use of part-time retirees to help mentor younger engineers has also been employed. Finally, Mr. Campbell testified that through a partnership with Ivy Tech Community College of Indiana, NIPSCO has worked to create curriculum content and otherwise assist in developing training programs that result in capable and interested candidates for utility industry positions. Mr. Campbell also identified the critical positions that are the focus of NIPSCO's efforts into the future for both management and represented (union) positions. *Id.* at 28-30.

Mr. Campbell testified that NIPSCO has stepped up recruiting for critical positions to bring replacements into the workforce six months to a year prior to the retirement of critical employees to allow the replacement workers to be mentored by more experienced employees prior to their retirement. He explained that the identification of replacement needs in advance also allows for the hiring of apprentices for bargaining unit positions to allow for training to take place prior to the occurrence of the vacancy. He also indicated that significant support will be required from the Human Resources Department to identify an optimized blend of new employees and contract workers to provide the most cost-effective solution. Campbell Direct at 30-31.

Mr. Campbell testified that NIPSCO incurs additional costs as part of its early hiring for critical positions primarily due to the temporary double staffing that takes place after a new employee is hired but before the incumbent retires. He indicated that those costs are increased by a multiplier to cover employee benefits, and that capital-related costs are subtracted. He testified that in the case of dual employees working on both the gas and electric sides of the business, an electric allocator is used to identify the electric-only costs. Campbell Direct at 31-32. Mr. Campbell sponsored Petitioner's Exhibit RDC-7 that documented the proposed adjustment over the five-year period from 2008 to 2012. That exhibit contained a five-year cost projection of $19,626,036, with annual projected expenses of between $2,031,703 in 2008 to $6,689,011 in 2010.

Mr. Campbell testified that the adjustment proposed is reasonable because by focusing on critical positions and their backfills, NIPSCO can continue to provide safe and reliable service at a reasonable cost along with a good balance of journeymen to apprentices to enable effective on-the-job training. He added that the incremental cost is a reasonable approach to ensure continuation of local expertise necessary to effective day-to-day operation of NIPSCO's generating stations and its transmission and distribution system. Campbell Direct at 33-34.

Mr. Campbell also presented testimony supporting Adjustment OM-8 sponsored by Petitioner's Witness Miller which concerned positions that were vacant in the test year. He testified that the $5,016,101 adjustment was intended to reflect additional staffing for vacancies that NIPSCO is actively seeking to fill. Mr. Campbell testified that the amount of the adjustment was calculated by using the salary or wage information for each of the 104 vacancies identified by Human Resources, and adding the cost for benefits and incentive compensation, identifying the portion of the vacancies that are electric-associated, and then subtracting the capitalized portion of the expense. Campbell Direct at 34. He explained that the positions not covered by a collective bargaining agreement are posted internally and on an external website. He added that positions covered by a collective bargaining unit are posted on all NIPSCO Union Bulletin Boards and that certain entry-level positions are also posted externally and advertised in local newspapers. *Id.* at 35.

NIPSCO Witness Timothy A. Dehring, NIPSCO's Senior Vice President, Energy Delivery, also submitted direct testimony that addressed specific aspects of the proposed aging workforce adjustment related to NIPSCO's electric transmission and distribution system. He testified that the critical positions identified in those areas were electric lineman, electric metermen, substation electricians, dispatcher operators, first line supervisors, and engineers. He explained that NIPSCO had experienced steady retirements in electric linemen resulting in a rapid growth of apprentices in lineman positions. Dehring Direct at 23. He indicated that NIPSCO had filled additional jobs over and above retirement levels in 2007 and anticipated continuing to do so. He testified that about 50 is the maximum number of apprentice lineman that NIPSCO can support with on the job training from experienced journeymen, and that the growth in the relative number of apprentices has resulted in increases in planned overtime among linemen. *Id.* at 23-24.

Mr. Dehring detailed the circumstances surrounding the need to address losses in experienced electric metermen and substation electricians, and noted that retirement among dispatcher operators was more critical even though the training cycle for those positions was only one year. He testified that about 80% of NIPSCO's dispatcher operators are currently eligible to retire, and that NIPSCO has four to five employees in training at a time in advance of anticipated retirements, and that NIPSCO had hired a dedicated trainer for this position. Dehring Direct at 24. He testified that NIPSCO's current strategy of hiring replacements as soon as retirements occur is inadequate because it has become increasingly difficult to train new hires with fewer first line supervisors and engineers. *Id.* at 25.

Mr. Dehring detailed NIPSCO's more proactive approach to filling jobs in advance of retirement. He testified that NIPSCO had created a five-year staffing plan for each of the critical positions in his area that includes the advance hiring of early replacements beginning in 2007. He testified that the planning process is also intended to reduce planned overtime necessitated by heavy reliance on less experienced workers as senior employees retire. Mr. Dehring sponsored Petitioner's Exhibit TAD-4 that summarized the five-year staffing plan for electric linemen and that showed the calculation of incremental staffing beyond 2007, exclusive of lineman positions specifically targeted for safety. Dehring Direct at 25. Mr. Dehring sponsored similar plans for the other four critical positions identified in Petitioner's Exhibits TAD-5 through Petitioner's Exhibit TAD-8.

(b) OUCC's Evidence. OUCC Witness Barbara A. Smith presented testimony that addressed many of the labor-related adjustments proposed by NIPSCO. Ms. Smith testified that the OUCC did not oppose NIPSCO's proposed Adjustment OM-5 to capture wage increases because the proposed adjustment was fixed, known and measurable. She testified that the OUCC also did not oppose NIPSCO's incentive compensation Adjustment OM-6 based on an analysis of testimony, workpapers and discovery. Smith Direct at 3-4.

Ms. Smith testified in opposition to NIPSCO's proposed aging workforce adjustment. She testified that NIPSCO has not experienced a lower employee count based on retirements in recent years, and that NIPSCO actually employed more workers during the test year than the average for the 2001-2007 time period. Smith Direct at 6. Ms. Smith testified that the number of retirees in 2007 was below the average retirements from 2003 to 2007, and was critical of the proposed adjustment because it was not dependent upon the occurrence of the projected retirements. *Id.* at 7. She testified that a significant downward adjustment was warranted for the removal of retirees' salaries to eliminate the overstatement of labor expense. *Id.* at 9. Ms. Smith also testified that NIPSCO's ability to accurately predict retirees was flawed, and instead recommended a different approach to aging workforce predicated on the actual expenses incurred during the 2008 adjustment period. She testified that NIPSCO could not be blamed for failing to foresee the economic collapse after the filing of its case-in-chief, but testified that the use of the actual 2008 amount would be a better reflection of workforce conditions. She proposed that NIPSCO be allowed recovery of the 2008 expenditures relating to aging workforce replacements of $2,223,128. *Id.* at 10-11.

Ms. Smith also testified on the issue of vacancies in NIPSCO's workforce captured in NIPSCO Adjustment OM-8. She testified that NIPSCO should not be authorized to recover costs associated with positions that do not represent incremental increases in base pay and incentive compensation, and instead proposed that the proposed pro forma adjustment of $5,016,101 be reduced to $2,766,995.[14] Smith Direct at 13. Ms. Smith applied a similar rationale to NIPSCO's proposed Adjustment OM-9 for the filling of the 83 new positions identified by Ms. Odum. She testified that by reducing the proposed adjustment for positions not backfilled, accounting for all new positions filled through March 11, 2009, and eliminating the capitalized portion, the OUCC calculated an appropriate adjustment for NIPSCO's electric operations of $4,637,695. *Id.* at 14-15.

(c) IG's Evidence. IG Witness Meyer testified that NIPSCO's proposed aging workforce adjustment was not reasonable because it is unnecessary in light of NIPSCO's current practices, is highly speculative, and encompasses events beyond the test year and adjustment period. He testified that the extensive evidence offered by NIPSCO established the adequacy of its hiring procedures. He asserted that the mega-bid process, increased training in the test year, and the partnership with Ivy Tech are examples of the adequacy of NIPSCO's existing tools. Meyer Direct at 3.

Mr. Meyer testified that the projected retirements embedded in NIPSCO's proposed adjustment were highly speculative, and that the actual experience in 2008 was proof that the projections were unreliable and the statistics were inflated. He testified that approval of an adjustment based on inflated projections will result in ratepayers overpaying until the adjustment is removed from rates in the next rate case. Meyer Direct at 4-5.

Mr. Meyer expressed his opinion that a utility proposing an adjustment that encompasses a time period beyond the test period should demonstrate the adjustment is required in order for the utility to earn its authorized return during the years the proposed rates are in effect. Meyer Direct at 5-6. He explained that other cost of service changes may occur during the five-year projection period of the adjustment that will not be captured in rates between cases. He testified that one example of such offsetting changes is that the proposed adjustment fails to capture savings associated with lower salaried workers being hired after retirements occur. He testified that the failure to capture those savings in the adjustment should lead the Commission to deny the proposal in its entirety. *Id.* at 6-8.

Mr. Meyer also opposed NIPSCO's proposed adjustment for the filling of test year vacancies. He testified that vacancies are commonplace, and that any adjustment approved should be for less than the full 104 vacancies in recognition of the fact that some vacancies always exist. He recommended that the adjustment be scaled back to recognize only those positions filled as of the close of the adjustment period. He also recommended that the approved adjustment incorporate only the minimum of the salary range for each position filled. He proposed that the adjustment be reduced from $5 million to $2.9 million in recognition of his recommendations. Meyer Direct at 9-11.

Similarly, Mr. Meyer recommended that NIPSCO's proposed adjustment for the addition of positions as part of the change to its organizational structure be reduced to reflect fewer

[14] Ms. Smith corrected her testimony during the evidentiary hearing to reduce her original recommendation from $4,087,646 to $2,766,995 in order to correct a mathematical error.

positions and lower salary. Mr. Meyer testified that in his opinion, some of the services to be provided by the 83 new positions must have been provided during the test year by NCS employees. Mr. Meyer contended that once the new positions were filled, NCS expenses would consequently decrease as services are transitioned to the new employees, so a pro forma adjustment to reduce NCS expenses should have been made. He concluded that only 49 of the 83 positions identified by Ms. Odum had been demonstrated to represent a supported additional employee hire. Mr. Meyer also recommended calculating the adjustment using the low end of the range salary data. Based on his application of the ratio of positions hired through December 31, 2008 to total positions requested, Mr. Meyer proposed a reduction in the proposed adjustment for new positions from $6.4 Million to $3.8 Million. Meyer Direct at 11-14.

Mr. Meyer also criticized NIPSCO's inclusion of incentive compensation dollars associated with the meeting of financial goals in its revenue requirement. He testified that in his view all employee payments under an acceptable incentive plan should be directly related to the achievement of operational performance goals in order to be recoverable in rates. Meyer Direct at 16. Mr. Meyer testified that he was opposed to the use of financial targets or earnings per share as a basis for the award of incentive payments because such targets may cause a reduction in the quality of service to customers. He testified that "it is entirely inappropriate to pass the costs of such profit-driven awards onto the ratepayers." *Id.* at 17. Mr. Meyer cited two Missouri Public Service Commission orders in support of his position, and also discussed the Commission's order in *PSI Energy, Inc.* Cause No. 40003 (Sept. 27, 2006), in support of his proposed standard that would exclude all earnings per share related incentive awards. Mr. Meyer proposed the disallowance of $2.5 million in addition to the proposed reduction in test year incentive payments proposed by NIPSCO to eliminate all incentive payments to union and non-exempt, non-union employees and one-half of the incentive payments made to exempt employees. Meyer Direct at 14-20.

(d) Petitioner's Rebuttal Evidence. In NIPSCO's rebuttal case, Mr. Campbell disagreed with the positions taken by OUCC Witness Smith and IG Witness Meyer opposing NIPSCO's proposed aging workforce adjustment. He explained that contrary to the assertions of Ms. Smith and Mr. Meyer, the difference between the projected and actual retirements for 2008 (the first year of the projection) does not impact the accuracy of the proposed adjustment. He testified that the use of a five-year average in the calculation of the adjustment was intended to account for single year fluctuations because individuals foregoing retirement in the first year would be more likely to retire in the second, and so forth. He explained that the average year approach is intended to smooth out the year-to-year variances in retirements caused by a variety of factors. Campbell Rebuttal at 2-3.

Mr. Campbell was also critical of Mr. Meyer's contention that an aging workforce adjustment was unnecessary based on NIPSCO's demonstrated ability to fill positions in the past. He explained that the Ivy Tech partnership and mega-bid strategy discussed in his direct testimony were beneficial regardless of the rate of retirement, but were not designed as a replacement for on-the-job training for critical employees. He testified that the cost of implementing the new program during the 2007 test year was subtracted from the calculation of costs going forward so as to arrive at a representative average. Mr. Campbell explained that the replacement of retiring workers in the past is not the same as the situation faced in the future because in the case of prior retirements, NIPSCO had a pool of qualified replacements from which to draw. He testified that the cumulative impact of the accelerated loss of experienced personnel will become greater as retirements increase, so it is necessary to work now to ensure that replacements are available when they occur. Campbell Rebuttal at 3-5.

Mr. Campbell testified about the process and analysis used to identify individual workers in critical positions which involved conversations with employees and their supervisors. For critical positions with larger populations of eligible employees (such as lineman and customer service center personnel), NIPSCO used projections based on the previous five-years of electric-related bargaining unit retirements. He testified that the results of that analysis were shown on exhibits sponsored by Mr. Dehring. Mr. Campbell also explained the difference between that analysis and the process used in his testimony to predict retirements of baby boomer generation employees which was intended to demonstrate the challenge faced by NIPSCO in dealing with the upcoming surge in retirements. Campbell Rebuttal at 5-7; Petitioner's Ex. TAD-4. Mr. Campbell clarified that the bar graph contained in his direct testimony was a predictive model for all employees developed from historical data, while the projected retirements among critical employees were determined according to the analysis based on discussions with employees and supervisors. *Id.* at 7.

Mr. Campbell disagreed with Mr. Meyer that the proposed aging workforce adjustment failed to capture savings from lower salaries associated with replacement workers. Mr. Campbell sponsored an exhibit that demonstrated that the aging workforce adjustment captures only the incremental cost during the overlap between the two positions. Campbell Direct at 8; Petitioner's Ex. RDC-R2. This exhibit, he stated, illustrates why the proposed adjustment did not result in a "double count" of costs. Finally, Mr. Campbell disagreed with Ms. Smith's proposal to calculate the adjustment based solely on the 2008 actual data on the ground that the five-year average used by NIPSCO is a more accurate reflection of the anticipated level of ongoing expense. *Id.* at 9.

Mr. Campbell testified that NIPSCO accepted the OUCC's proposed modifications to proposed Adjustments OM-8 and OM-9 to reflect the number of employees actually hired. Campbell Rebuttal at 10, 11. The reduction for Adjustment OM-8 was agreed to be $2,766,995, and for Adjustment OM-9 was agreed to be $4,637,695.[15] Mr. Campbell disagreed with the additional reductions proposed by Mr. Meyer because Mr. Meyer's proposal assumed that all positions would be filled at the minimum salary level. Mr. Campbell said such an assumption is unrealistic and unsupported by market information. In Mr. Campbell's experience, individuals are hired at different points within the salary range based on experience, qualifications and other measurable criteria. He noted that NIPSCO's agreement to the OUCC proposals for Adjustments OM-8 and OM-9 incorporated actual salary data. Campbell Rebuttal at 10-11.

With respect to NIPSCO's incentive compensation plan, Mr. Campbell testified that Mr. Meyer had misunderstood the plan because performance metrics are built into the discretionary portion of NIPSCO's plan. He testified that in order to qualify for the discretionary portion of the incentive plan, metrics for safety, operational and reliability measures, and customer satisfaction would necessarily have been met, thus providing benefits to ratepayers. He also testified that Mr. Meyer had misunderstood the corporate financial measures used in the incentive plan as earnings per share, when the actual metric is *operating* earnings per share that normalizes for weather. Mr. Campbell testified that NIPSCO's proposed adjustment satisfied all

[15] The amount of the adjustments was contained in NIPSCO Witness Miller's rebuttal testimony and exhibits, but Mr. Campbell indicated agreement with the OUCC's calculation.

three legs of the Commission standards set forth in *PSI Energy, Inc.*, Cause No. 42359, for recovery of incentive compensation, including the requirement that shareholders bear responsibility for a portion of the incentive payments. Campbell Rebuttal at 11-13.

(e) Discussion and Findings.

(i) Incentive Compensation. The Commission has long recognized the value of incentive compensation plans as part of an overall compensation package to attract and retain qualified personnel. The criteria for the recovery of incentive compensation payments through rates are well settled in Indiana: (1) the incentive compensation plan is not a pure profit sharing plan, but rather incorporates operational as well as financial performance goals; (2) the incentive compensation plan does not result in excessive pay levels beyond what is reasonably necessary to attract a talented workforce; and (3) shareholders are allocated part of the cost of the incentive compensation programs. *See, e.g., PSI Energy, Inc.*, Cause No. 42359, at 89. IG witness Meyer proposes to disallow all of NIPSCO's incentive compensation plan costs. IG Ex. Exhibit GRM-3. NIPSCO maintains these costs satisfy the criteria for recovery. No party asserts that NIPSCO's incentive compensation plan results in excessive pay levels. We focus on the two remaining criteria to evaluate Mr. Meyer's adjustment.

First, NIPSCO's incentive plan cannot be said to be a pure-profit sharing plan which only incents employees to become more profitable. *Ind.-Am. Water Co.*, Cause No. 42029, at 45 (Nov. 6, 2001). Components of NIPSCO's plan are indisputably based on operational performance metrics of the type we have required to be included in recoverable plans in prior orders. Mr. Meyer proposes to eliminate recovery of all of the costs because he understood the incentive payments are dependent upon NiSource's achievement of a financial trigger for an applicable calendar year rather than operational incentives. Mr. Campbell testified, however, that NIPSCO's incentive plan also incorporates operational performance goals by considering metrics like safety and reliability measures in awarding incentive pay to exempt employees. Basing the incentive pay of these leaders on operational performance metrics gives them an incentive to ensure the employees that report to them, including union and non-exempt non-union employees, focus on service to ratepayers. Mr. Campbell also testified that achievement of financial goals provides benefits to ratepayers and shareholders. We agree a balanced approach to controlling costs and efficiently serving customers can both improve a utility's bottom line and benefit ratepayers in the short- and long-run.

We also believe that Mr. Meyer's adjustment inappropriately allocates the entire incentive pay cost to shareholders. This proposal is inconsistent with our conclusion that NIPSCO's incentive plan includes operational requirements and is not a pure profit sharing plan. Under our criteria, once an incentive compensation plan is found to provide benefits to shareholders and ratepayers and not be excessive, an appropriate level of costs should be recovered from ratepayers who are benefited by these programs. Mr. Campbell explained that NiSource's shareholders are already allocated a portion of the incentive plan costs because NIPSCO's adjustment only includes incentive compensation at the trigger level which is 50% below the target amount, leaving shareholders to cover the target and stretch levels. Thus, NIPSCO's adjustment reduces electric test year incentive compensation expense by $916,264. Miller Direct at 20. NIPSCO's adjustment is consistent with incentive compensation adjustments that we have previously approved for other utilities. *See Ind.-Am. Water Co.*, Cause No. 43187, at 12 (Oct. 10, 2007); *Ind.-Am. Water Co.*, Cause No. 42520, at 88 (Nov. 18, 2004);

PSI Energy, Inc., Cause No. 42359, at 88-89. Because NIPSCO's plan satisfies the general criteria for cost recovery, we accept NIPSCO's incentive compensation adjustment.

(ii) Aging Workforce. This is not the first time that the Commission has been faced with a proposal to address aging in the utility workforce. Both Vectren and I&M have proposed variations on the aging workforce theme. Though each of those proposals ultimately became moot as a result of settlement, we are nonetheless cognizant that the demographic characteristics of the workforce at large are particularly problematic for the utility industry that is highly reliant upon experienced and skilled workers to maintain their critical infrastructure.

In evaluating the adjustment proposed by NIPSCO, we must first evaluate whether the conditions faced by the utility warrant consideration of an adjustment to account for them. We conclude that the evidentiary record here supports the conclusion that such conditions exist. While both OUCC Witness Smith and IG Witness Meyer were critical of the specific mechanics of NIPSCO's proposal, it is undisputed that more than half of NIPSCO's employees in critical positions will be eligible for retirement by 2012. While it is difficult to project how external factors may influence individual retirement decisions, the undeniable reality is that NIPSCO will be faced with the need to replace a large number of its most experienced personnel in the foreseeable future.

Having concluded that NIPSCO is faced with conditions sufficient to warrant consideration of its aging workforce proposal, we must next assess whether existing hiring practices and initiatives are adequate to enable the utility to bridge the gap the proposal is intended to address. Both Mr. Campbell and Mr. Dehring described the range of efforts undertaken to accelerate the hiring and training of new workers in time to develop the experience and expertise to fill the positions that NIPSCO identified as critical. While Mr. Meyer questioned why NIPSCO's existing measures were not adequate to address the aging of its workforce, we note that Mr. Meyer offered no evidence to explain why NIPSCO's current measures were sufficient. Moreover, there was also no evidence disputing that the positions selected were critical to the success of NIPSCO in providing safe and reliable service.

We now turn to an examination of the methodology proposed by NIPSCO for the calculation of its proposed adjustment. Both the OUCC and IG were critical of NIPSCO's proposal as speculative and imprecise because it relies on projections of future retirements rather than on known events. We are concerned that many adjustments based on projections are not representative of an ongoing level of future expense. However, the fact that projected data is used does not in and of itself disqualify a proposed adjustment unless it is clear that the data relied upon or the projection methodology employed is suspect. That is not the case here. The use of a five-year average, when taken in the context of the undisputed evidence about the age of NIPSCO's critical workforce, is reasonable as a technique to smooth expected variations in retirements. This is the case because the projection techniques themselves are sufficiently sophisticated to be reasonable, and because the advanced age of the workforce dictates that predictable retirements will occur sometime within the five-year period. We find Mr. Campbell's rebuttal testimony to be persuasive in that regard because it clearly explained how and why the actual 2008 retirements did not impact the proposed adjustment.

Finally, we find that the proposed adjustment is conservative because it proposes recovery of only the "overlap" dollars for the period when a replacement worker is on the payroll prior to the retirement of the current employee. We disagree with Mr. Meyer's position that the proposed adjustment fails to account for savings associated with the lower paid replacement based on the explanation of the adjustment in Mr. Campbell's rebuttal testimony. We also note that while the OUCC disagreed with NIPSCO's calculation of the aging workforce adjustment, it supported recovery of actual 2008 dollars spent for early replacement of retiring workers, an amount $1.7 million lower than that proposed by NIPSCO.

We find that the aging workforce Adjustment OM-7 of $3,925,207 proposed by NIPSCO is reasonably representative of the actual expenses to be incurred during the life of the rates approved in this proceeding and should be approved. However, as Mr. Campbell testified that its proposed adjustment is based on projected retirements through 2012, we similarly find that the adjustment approved shall apply through 2012—upon the conclusion of 2012, NIPSCO shall file a tariff revision eliminating this adjustment.

(iii) Vacancies and Reorganization. In evaluating adjustments to test year staffing levels and associated expenses proposed by the parties, the question is whether the proposed expense is fixed, known, and measurable and is reasonably representative of ongoing levels of operating expense of the utility. In this case, NIPSCO agreed to the OUCC's proposal for an ongoing expense that captures actual hirings as of a specified date even though that expense level was below that which NIPSCO initially proposed. We find that the test year labor expense, as adjusted by the amount agreed to between NIPSCO and the OUCC, is representative of the ongoing expense NIPSCO is likely to experience during the life of the rates approved in this proceeding and should be approved. In approving that ongoing expense level, we reject Mr. Meyer's proposal to base the adjustment on the assumption that all employees hired to fill vacancies or to staff newly created positions would be filled at the minimum of the applicable salary range, especially because the adjustment we approve is based on actual rather than theoretical salaries.

(2) Pension Expense. In its prefiled case-in-chief, NIPSCO proposed a five-year average for pension expense. During cross-examination and redirect examination of Ms. Miller during the presentation of NIPSCO's case-in-chief, Ms. Miller explained that NIPSCO has experienced a significant increase in pension expense as a result of the market collapse in the fall of 2008. Tr. at P-55–P-57, P-83–P-86, and P-92–P-94. NIPSCO's pension expense for 2009 was determined as of December 31, 2008. She sponsored a redirect exhibit showing a recalculated five-year average including 2009 and dropping out 2004. The updated five-year average increased the pension expense adjustment from $5,762,558 (Petitioner's Ex. LEM-3, Adjustment OM-3) to $10,188,010 (Petitioner's Redirect Ex. 2). Although no party contested this calculation, neither the OUCC nor IG included the updated adjustment in their proposed revenue requirements. On rebuttal, Ms. Miller sponsored an exhibit further updating the adjustment from $10,188,010 to $10,489,229 to reflect a slight change resulting from finalization of the books at the end of 2008. Miller Rebuttal at 51-52; Petitioner's Ex. LEM-R3, Adjustment OM-3.

We find that NIPSCO's original five-year average is appropriate, and accordingly find the pension expense adjustment of $5,762,558 shall be approved.

(3) Variable Production O&M Expense.

(a) Evidence. NIPSCO Witnesses Pack and Sweet supported

Adjustment OM-2, which increased test year operating expenses by $4,001,238 to normalize the variable costs required to operate NIPSCO's generating facilities. Miller Direct at 14. Mr. Pack explained that NIPSCO's generation fleet experienced three unusually long outages in 2007. Unit 7 required two outages totaling 25 weeks to combine maintenance with the installation of environmental control equipment. Unit 10 suffered an equipment failure and delays in obtaining replacement components resulting in an 11-month outage during the test year. Equipment failure also caused Unit 16A to suffer an unusual outage for the last five months of the test year. Mr. Pack noted that these outages were unusual and not expected to occur in the future. Pack Direct at 5. Mr. Sweet explained that test year expenses should be adjusted to include run time by: (1) three months for Unit 7; (2) eleven months for Unit 10; and (3) five months for Unit 16A. Sweet Direct at 11.

OUCC Witness Catlin opposed NIPSCO's adjustment because he believed the PROMOD generating dispatch model run used to calculate the adjustment should be re-run to reflect Sugar Creek's dispatch into the Midwest ISO along with NIPSCO's other units. Mr. Catlin testified that NIPSCO had not prepared such an update of its model and, until such an update was presented, the OUCC opposed the adjustment. Catlin Direct at 12-13.

IG Witness Meyer also opposed NIPSCO's variable production O&M expense adjustment. Mr. Meyer testified NIPSCO's test year production expense (less fuel) was already too high based on historical trends. *Id.* at 21-22. For that reason, he contended that NIPSCO's adjustment should be rejected. Meyer Direct at 20-23.

In rebuttal, NIPSCO Witness Shambo asserted that NIPSCO's proposed adjustment to normalize the effect of unusual outages is reasonable, and pointed out that neither Mr. Catlin nor Mr. Meyer presented any convincing evidence to the contrary. Mr. Shambo testified that the dispatching of NIPSCO's generating stations is dependent upon the economic dispatch determinations of Midwest ISO; and it is Midwest ISO's algorithms, not NIPSCO or NIPSCO's load, that determine the least cost dispatch outcomes. Mr. Shambo concluded that because NIPSCO's coal-fired units are dispatched for energy before Sugar Creek is dispatched, the incorporation of Sugar Creek will not impact the dispatch of NIPSCO's other generating units. Shambo Rebuttal at 17-18. Mr. Shambo noted that NIPSCO is willing to incorporate the position of IG and MU that NIPSCO's non-fuel O&M expense should be treated as 90% fixed and 10% variable which would have a modest impact on the proposed $4,001,238 adjustment. NIPSCO did not anticipate a material difference in the cost of service study results. *Id.* at 20. Mr. Pack similarly refuted the claim that the inclusion of Sugar Creek in the PROMOD model would materially affect the adjustment. He explained the primary driver for the adjustment was the outage at Unit 7, which has a lower operating cost than Sugar Creek. Given those cost relationships, Mr. Pack emphasized, Sugar Creek would not be dispatched by the Midwest ISO unless Unit 7 has already been dispatched. Pack Rebuttal at 9.

(b) Discussion and Findings. No party disputes that NIPSCO experienced lengthy, unusual outages at three of its generation facilities during the test year. NIPSCO does not expect these outages to occur in the future. NIPSCO's proposed methodology was to adjust its variable O&M expenses to reflect a more typical operation year by using 2003 through 2005 data to create a percentage allocator applied to test year costs. This cost was then compared to its PROMOD model, which NIPSCO used to create a hypothetical operation scenario based upon test year inputs. The difference between these two calculations resulted in NIPSCO's proposed adjustment.

NIPSCO's methodology appears to ignore test year variable O&M expense and instead utilize historic data to restate this expense on a going forward basis. While we are cognizant that NIPSCO experienced more outages in the test year than in prior years, NIPSCO has not carried its burden of persuading the Commission that its methodology appropriately reflects an adjustment to this test year expense. Accordingly, we make no adjustment to NIPSCO's variable O&M expense.

(4) Gasoline And Diesel Fuel Expense. NIPSCO Witness Miller sponsored Adjustment OM-15, which increased test year operating expenses in the amount of $799,403 to reflect higher gasoline and diesel fuel costs. Ms. Miller testified that the average cost of bulk gasoline and diesel fuel during the 2007 test year was updated to reflect March 2008 costs. Miller Direct at 25. Ms. Miller also sponsored Adjustment FP-4, which increased test year operating expenses in the amount of $840,335 for the higher cost of diesel fuel used in the fuel handling equipment in the generating stations. Miller Direct at 14-15.

OUCC Witness Catlin testified that the prices used by NIPSCO in developing its adjusted gasoline and diesel fuel costs were too high and not representative of NIPSCO's ongoing costs. Mr. Catlin explained that through discovery NIPSCO indicated that it paid $1.93 per gallon for diesel fuel in January 2009, compared to a price of $4.032 per gallon as of June 2008. For gasoline, NIPSCO reported that it paid $1.92 per gallon in January 2009 versus $4.386 per gallon in June 2008. Mr. Catlin proposed adjusting gasoline and diesel fuel costs to reflect the January 2009 prices paid by NIPSCO. Catlin Direct at 11-12.

IG Witness Meyer recommended that NIPSCO's gasoline and diesel fuel expense adjustments be disallowed, arguing that the projected increase in gasoline and diesel fuel expenses have not materialized. Mr. Meyer opined that the price paid by NIPSCO in January 2009 indicates that no adjustment needs to be made to the test year levels of gasoline and diesel fuel expenses or to NIPSCO's revenue requirement. Meyer Direct at 23-24.

In rebuttal, NIPSCO Witness Miller agreed that the price of gasoline and diesel fuel has declined since June 2008, but noted that prices have recently increased and are expected to fluctuate. Therefore, Ms. Miller proposed as an alternative to use a two-year average (January 2007 – December 2008) of gasoline and diesel fuel prices. Using these averages results in revised adjustments of $185,586 for Adjustment FP-4 and $138,596 for Adjustment OM-15, as reflected in Petitioner's Exhibit LEM-R2, page 1 of 3, lines 21 and 42. Miller Rebuttal at 44.

In recent years, there has been significant volatility in the price of gasoline and diesel fuel. As a result of that volatility, pricing the fuel at any particular spot date is problematic. Accordingly, we find that NIPSCO's rebuttal proposal to use a two-year average is appropriate and should be accepted.

(5) Weather Normalization. Consistent with our finding on the revenue adjustment, we adjust NIPSCO's fuel and purchased power expense by $408,324 to reflect the lower sales volumes reflected in the weather normalization adjustment discussed above.

(6) Service Company Allocations and Allocation of Common Costs.

(a) Petitioner's Evidence. Susanne M. Taylor, Controller for NCS, testified about NCS and the role it serves within NiSource, and provided support for the annualized level of fixed, known and measurable NCS charges applicable to NIPSCO. Ms. Taylor explained that NCS is a subsidiary of NiSource and an affiliate of NIPSCO within the NiSource corporate organization. She testified that NCS provides a range of services to the individual operating companies within NiSource, including NIPSCO, and coordinates the allocation and billing of charges to the operating companies for services provided by both NCS directly and by third-party vendors. Taylor Direct at 3.

Ms. Taylor testified that expenses are billed to operating companies by NCS in two ways: through contract billings and through convenience billings. She explained that contract billings are identified by job order and cover NCS labor and expenses associated with a specific project or cost center/department, and are billed according to the terms of individual Service Agreements with each affiliate. In contrast to contract billings, she testified that convenience billings reflect payments that are routinely made on behalf of affiliates. She cited employee benefits, corporate insurance, leasing, and external auditing as examples of ongoing corporate-wide expenses that are handled through convenience billings as a convenience to the vendor to eliminate the need for individual invoices to each affiliate entity. NCS makes the payment to the vendor and the charges for the services are recorded directly on the books of the affiliate. Taylor Direct at 4.

Ms. Taylor sponsored a copy of the most recent NCS Service Agreement with NIPSCO and explained that with the exception of the Virginia affiliate, each of the NiSource operating companies has an identical Service Agreement with NCS. She testified that the previous NIPSCO Service Agreement was superseded in 2007, but that the way individual expenses were allocated and billed under the two agreements was the same. Taylor Direct at 5-6. Ms. Taylor also sponsored an exhibit showing the unadjusted total NCS billings to NIPSCO during the test year of $73,988,195 broken down by service category. Petitioner's Ex. SMT-3. Ms. Taylor identified and explained each of the service categories that made up at least 3% of the test year unadjusted total as Information Technology, Operations Support and Planning, Legal, Rate, Employee, Customer Billing, Collection and Contact, Accounting and Statistical, Office Space, Corporate, and Purchasing, Storage and Disposition. *Id.* at 7-11.

Having discussed the structure of the relationship between NIPSCO and NCS, the ways services are billed, and the categories of services provided, Ms. Taylor explained the job order process within NCS that is used to ensure that charges are correctly charged to the right operating company(s) for each project. She explained that NCS creates a job order for each project or related group of projects and that each job order is assigned a ten digit number that captures information about how expenses for the project are to be charged. She explained that job orders that directly bill costs to individual affiliates like NIPSCO are strongly favored, but that some projects necessarily involve more than one affiliate, and in those cases, job orders that allocate costs among the participating affiliates is used. Taylor Direct at 12.

Ms. Taylor testified that when a project is initiated, a decision is made jointly by representatives of the operating company affiliate and NCS about whether the costs could be directly billed to one affiliate or should be allocated among several participating companies. She testified that an allocation code is assigned to each job order that identifies how costs are to be allocated among which operating companies, and that the assigned allocation code remains constant throughout the project, to ensure consistency throughout the project life, unless a change occurs in the identity of the affiliates participating in a specific job order. As a control, she explained that only a few individuals within the NCS accounting department have authority to create or modify job orders to ensure consistency. Taylor Direct at 12-13.

In her direct testimony, Ms. Taylor testified that NCS uses thirteen Bases of Allocation that are filed annually with FERC and that were previously approved by the Securities and Exchange Commission ("SEC"). Taylor Direct at 13. Petitioner's Exhibit SMT-4 described in detail each of those Bases of Allocation. *Id.* at 14. She explained that all services provided to NIPSCO are billed at cost, and that the 2007 Service Agreement provides that charges allocated to NIPSCO may be reviewed and challenged as a matter of right. *Id.* at 15.

Ms. Taylor sponsored two adjustments to the test year allocation of NCS costs to NIPSCO. The first of these adjustments was made to remove one-time, non-recurring charges totaling $5,025,326 from test year NCS allocations. Taylor Direct at 15; Petitioner's Ex. SMT-6. This adjustment was made up of three components. First, Ms. Taylor reduced test year expenses by $3,961,081 to remove NIPSCO's share of costs associated with the restructuring of the NiSource outsourcing contract with IBM, and for the one-time costs associated with the design assessment and configuration of a new Work Management system. Second, Ms. Taylor explained that $990,780 had been adjusted out of test year NCS allocations for a number of miscellaneous costs that were either non-recurring or inappropriate for rate recovery. These adjustments related to the Marble Cliff facility, the sale of mainframe equipment, the sale of certain real estate, and elimination of certain dues, memberships and lobbying expenses. *Id.* at 16-17. Finally, Ms. Taylor explained the elimination of $73,466 of incentive compensation expense to true-up the 2007 expense with a previously recorded accrual. *Id.* at 17.

Ms. Taylor explained that the second pro forma adjustment totaling $2,242,932 was made to reflect ongoing level of NCS expenses. She explained that this second adjustment was made to reflect the impact of payroll and benefit increases made during the adjustment period, a reduction in incentive compensation expense to reflect anticipated lower payout for 2008, and to reflect an increase in annual IBM fixed fees consistent with the escalation provision of the contract with IBM. Taylor Direct at 18. Inclusive of her two downward adjustments netting $2,782,395, Ms. Taylor documented adjusted test year NCS expenses of $71,205,800. Petitioner's Ex. SMT-6. Finally, Ms. Taylor noted an entry was required to test year NCS expenses to reflect the transfer of certain amounts related to capital, stores expenses and certain deferral accounts so that the total ties accurately for cost of service purposes. Taylor Direct at 18-19.

NIPSCO Witness Hershberger presented testimony that addressed how costs billed by NCS are handled within NIPSCO. Mr. Hershberger testified that NIPSCO receives an electronic invoice from NCS on a monthly basis that includes detailed line item charges in a coding structure that allows an understanding of the charge, the internal department responsible, the job order and sub codes applicable to the charge, the allocation basis or direct charge code, along with descriptive information about each charge. Hershberger Direct at 11.

Mr. Hershberger explained that NCS charges billed to NIPSCO are booked based on a mapping process that identifies the department responsible for each charge and then maps the charge to the appropriate NIPSCO gas, electric, or common account. Mr. Hershberger also described how NIPSCO's account mapping is updated manually each time a new NCS Job Order or Sub Code is created. Mr. Hershberger added that effective January 1, 2008, NIPSCO changed its mapping process to accommodate NCS's adoption of FERC Rule 684 requiring that service company charges be correlated to the FERC USOA. Hershberger Direct at 11-12.

Mr. Hershberger described the options available under the Service Agreement with NCS for the review and challenge of charges billed to NIPSCO through NCS. He explained that NIPSCO has ten days from the receipt of the detailed invoice to identify questions and concerns with monthly charges, and testified that issues identified are generally addressed during regular interactions between the two companies. In his direct testimony, Mr. Hershberger noted that NCS costs are billed to NIPSCO on a total company basis, rather than individually to its gas and electric operations. He clarified that common costs associated with functions common to both gas and electric are allocated internally using NIPSCO's common cost allocation ratios that generally replicate the method used by NCS to allocate charges to NIPSCO. Hershberger Direct at 12-13.

Mr. Hershberger sponsored Petitioner's Exhibit MEH-5 that demonstrated the calculation of the impact of Ms. Taylor's proposed pro forma adjustments to test year NCS expenses. Petitioner's Exhibit MEH-5 identified two categories of costs included in Ms. Taylor's proposed $2,782,395 downward adjustment: those costs carrying specific accounts and those "Unidentified" charges without a specific associated account. Mr. Hershberger testified that the total impact to NIPSCO's electric function from Ms. Taylor's proposed adjustments was a decrease to test year electric expenses of $1,215,130 and an increase to electric capital of $97,580. He explained that these calculations were based on the application of NIPSCO's common cost ratios to the charges identified in Ms. Taylor's adjustments. Hershberger Direct at 14-15.

Mr. Hershberger testified that in addition to his determination of the portion of Ms. Taylor's adjustment to test year NCS expenses applicable to NIPSCO's electric business, NIPSCO undertook an additional analysis of third-party vendor invoices to ensure that the proposed level of test year expense was compiled accurately. He explained that NIPSCO focused on third-party invoices because its personnel were more familiar than NCS with the various gas and electric projects, and thus could most readily identify charges that should not be charged to NIPSCO's electric operations. Mr. Hershberger testified that a review of 3,000 of the individual third-party invoices during the test year captured more than 99% of the total vendor costs during the test year, and resulted in four proposed adjustments to test year expenses. Hershberger Direct at 15-16.

Mr. Hershberger explained the four adjustments resulting from the review of individual test year invoices in his direct testimony. The four adjustments were: (a) a reduction in test year expenses of $704,715 to remove costs solely attributable to NIPSCO's gas operation; (b) an increase in test year expenses of $563,795 to reflect reassignment of charges that relate solely to the electric operation that were incorrectly booked to both gas and electric operations; (c) a decrease in test year expenses of $978,561 to eliminate costs not properly included in NIPSCO's regulated electric books; and (d) an increase in test year expenses of $15,840 to adjust the remaining invoices not individually reviewed by the percentage change resulting from specific invoice review. The adjustments were compiled in Petitioner's Exhibit MEH-6 and resulted in an overall reduction in test year expenses of $1,103,641. Hershberger Direct at 16. That amount formed the basis of Adjustment OM-17 sponsored by NIPSCO Witness Miller. Miller Direct at 26. Mr. Hershberger added that the comprehensive review undertaken in the calculation of the test year NCS expense gave rise to an improved, three part protocol for the review and processing of NCS invoices on a prospective basis. Hershberger Direct at 16-17.

Mr. Hershberger's direct testimony also addressed the allocation of common costs between NIPSCO's gas and electric operations. He explained that common costs incurred by both gas and electric operations have historically been allocated based on an allocation study performed by Arthur Anderson in 1968. Hershberger Direct at 8. He testified that the allocation ratios resulting from that study were reviewed beginning in 2006 to determine whether they were still reflective of cost causation. *Id.* Mr. Hershberger explained that it was determined that a majority of the ratios remained accurate, but that some ratios were no longer reflective of current operating conditions, and new ones were required to directly align NIPSCO's allocation with the allocation methodology employed by NCS for certain corporate costs. *Id.* at 8-9.

Mr. Hershberger specifically identified the former Composite Ratio A as no longer accurate and reflective of cost causation. He explained that Ratio A was a basic average of four components including gross utility revenues, transmission and distribution expenses, the number of customers, and gross plant. He testified that Ratio A was inappropriate for current use because utility gross revenues had become highly volatile based on fluctuations in gas and fuel prices, and because it did not account for electric production or gas storage. Hershberger Direct at 9.

Mr. Hershberger testified that former Composite Ratio A was replaced by a new Ratio O&M that is similar to the allocation methodology (Basis 20) used by NCS. Hershberger Direct at 10. Mr. Hershberger sponsored Petitioner's Exhibit MEH-4 that detailed the revised common allocation ratios in effect at the close of the test year and forward, and used in the preparation of Adjustment OM-18 sponsored by Ms. Miller. Adjustment OM-18 was an increase to the test year levels of $3,187,121. He explained that the common cost allocation ratios are recalculated twice per year to incorporate current information and are representative of the way common costs are incurred by NIPSCO. *Id.* at 9-10.

(b) IG's Evidence. IG Witness Greg Meyer presented testimony in response to NIPSCO's proposed Adjustment OM-17. He testified that the allocators used by NCS necessarily result in the assignment of more costs to NIPSCO than other NiSource affiliates. Mr. Meyer identified four of the Bases of Allocation identified by Ms. Taylor that he contended were biased toward an assignment of more costs to NIPSCO - Basis 1 (Gross Fixed Assets and Total Operating Expenses), Basis 2 (Gross Fixed Assets), Basis 7 (Gross Depreciable Property and Total Operating Expenses), and Basis 20 (Direct Costs). Meyer Direct at 34-35.

Mr. Meyer was critical of Bases 1, 2, and 7, asserting that the comparatively high production costs associated with NIPSCO's electric operation mathematically skews cost allocations toward NIPSCO in comparison to its less intensively capitalized gas operations. He criticized Basis 20 because of the potential to create a "snowball effect" whereby more and more costs would be allocated to NIPSCO over time because of the comparative magnitude of bills over prior periods. He testified that it was necessary to evaluate the costs assigned to all NiSource affiliates in order to determine whether a bias exists in the allocators used by NCS. Meyer Direct at 34-36.

Mr. Meyer presented a table showing NIPSCO's proportionate share of NCS direct and allocated costs for the period 2005 through 2007, and noted that NIPSCO was billed 15.31% of total NCS direct expenses, and 24.69% of its allocated expenses during the test year. He testified that the bills tendered to NIPSCO by NCS are insufficient to determine how any individual expense was allocated. He testified that in order to track a cost from NCS to NIPSCO, it would be necessary to know the charge code, the job code and the sub code under which the cost was allocated by NCS. Mr. Meyer was also critical of NIPSCO's method for allocating common costs between its gas and electric operations. Mr. Meyer contended that the process is not transparent and that the documentation necessary to enable a full tracking of a cost at NCS through to NIPSCO electric are generally not available. Mr. Meyer agreed that the common cost allocation ratios mirror those used to allocate costs at the NCS level, but voiced the same concerns that those ratios also over allocate costs to NIPSCO's electric operations. Meyer Direct at 36-38.

Mr. Meyer claimed that the adoption of new common cost allocation ratios such as Ratio O&M was undertaken to take advantage of a shift in common costs from NIPSCO's gas to NIPSCO's electric operations in preparation for this proceeding. He disagreed with Mr. Hershberger that Ratio O&M was needed because the former Ratio A captured too much fluctuation in gas prices based on the fact that the previous ratio had resulted in a steady allocation of costs since 1985. He testified that 61.25% of NIPSCO's 2007 NCS charges had been allocated to its electric operations, an increase of about $14 million over the allocation that would have occurred under the previous allocation ratios. He claimed that NIPSCO's Controller was not in a position to protect NIPSCO's electric interests during the allocation process. Meyer Direct at 39-40.

Mr. Meyer also criticized NIPSCO's use of Ratio O&M for the allocation of costs that had been direct billed to NIPSCO by NCS. He testified that those costs made up $11.029 million out of the $17.948 million in test year common costs allocated to NIPSCO electric. He contended that because NCS had identified a way to directly assign those costs to NIPSCO at the corporate level, NIPSCO should also be able to evaluate those costs and individually assign them to gas or electric operations. He concluded that more time should be taken by NIPSCO to examine the proper assignment of costs. Mr. Meyer calculated that the 61%/39% split between electric and gas allocation of common costs was reduced to a 55%/45% split by removing the costs allocated to NIPSCO by NCS, and contended that calculation supported his conclusion that costs to NIPSCO's electric operations had been overstated and that those costs should therefore be eliminated when calculating the common cost allocation percentage. Meyer Direct at 41-43.

Mr. Meyer made four recommendations concerning NCS allocations and the allocation of common costs. First, he recommended that proposed Adjustment OM-18 be disallowed. Second, he recommended that NIPSCO's O&M expenses be adjusted downward by $10.8 million to reflect the application of NIPSCO's previous common cost allocation ratios. Third, he recommended a $25 million reduction in NIPSCO's rate base to reflect the application of NIPSCO's previous common cost allocation methodology to capital accounts. Fourth, he recommended that the Commission open a subdocket to require the filing of a complete allocation study from NCS and NIPSCO, and that any award of NCS costs in this proceeding be made interim and subject to refund pending the outcome of that subdocket. Meyer Direct at 44.

(c) NIPSCO's Rebuttal Evidence. NIPSCO submitted rebuttal evidence from Susanne Taylor that addressed claims made by Mr. Meyer. Ms. Taylor testified that Mr. Meyer's contention that NCS allocates excessive costs to NIPSCO was premised on a misunderstanding of how Bases of Allocation are used by NCS to apportion charges to affiliates, and that his criticisms were unsupported by an examination of the actual charges and their allocations. She explained that Mr. Meyer's position failed to recognize that each project job order delineates specific companies to which costs are allocated. She explained that only 5.1% of the total company NCS charges were allocated using Basis 1, and that those dollars involved either gas-only or Indiana specific projects (in which NIPSCO's exposure to cost allocation was appropriate), or certain IT-related projects appropriately billed under Basis 1. Taylor Rebuttal at 2.

Ms. Taylor explained that Mr. Meyer's criticisms of Basis 2 and Basis 7 were unfounded because Basis 2 had been used for only a single correction entry during the test year, and Basis 7 is used exclusively for the allocation of insurance premiums that are driven directly by gross depreciable property and O&M upon which Basis 7 allocations are made. She also rejected Mr. Meyer's criticism of Basis 20 and testified that cost allocation under Basis 20 actually saves NIPSCO money in comparison to the allocation of common charges using other Bases of Allocation. She noted that the SEC had stated a preference for Basis 20 during its audit of NCS because it most fairly allocates costs among all affiliate companies. Taylor Rebuttal at 2-3.

Ms. Taylor agreed that allocators must be carefully selected to accommodate the fact that NIPSCO is the only electric utility among the NiSource family of companies. However, she disagreed with the hypothetical example of an NCS employee working solely for NIPSCO. She testified that it is NCS's position that such dedicated personnel should be on NIPSCO's payroll, and that NCS personnel typically provide or have the ability to provide service to more than one operating company. Taylor Rebuttal at 3-4.

Ms. Taylor reiterated that NCS is very careful in establishing allocators to ensure that individual affiliates are not billed for inappropriate charges. She noted that NCS is involved in regulatory filings on issues of cost allocation in many of the other states where NiSource utilities provide service and that expense allocations for both contract and convenience billings are routinely subject to regulatory auditing and review. Further, NiSource employs an independent accounting firm, Deloitte and Touche LLP ("Deloitte"), to test NCS's expense allocations for both contract and convenience billings as part of their audit procedures used to support their outside opinions on the financial statements of NIPSCO. None of these reviews have required adjustments related to NCS allocations. Taylor Rebuttal at 4.

Finally, Ms. Taylor disagreed with Mr. Meyer's assertion that NCS contract billing invoices were insufficient to determine how particular expenses had been allocated. She again explained that the Charge Codes that appear for each line item contain information from which the allocation and origin of each charge can be readily identified, and noted that processes exist for the review and challenge of NCS allocations if additional clarification is required. Taylor Rebuttal at 5.

NIPSCO's Accounting Manager Shirley M. Rippy provided rebuttal testimony that explained the process used by NIPSCO to review monthly NCS billings. She explained that NIPSCO receives monthly billing files from NCS that identify invoice numbers and either direct billing codes or corporate allocations used to identify how each item came to be billed to NIPSCO. NIPSCO also has access to the underlying electronic invoices. She testified that the financial analyst responsible for reviewing the invoice automatically prints invoices greater than

$10,000 for review during monthly meetings that involve the Controller, accounting managers and financial analysts. She clarified that each expense is reviewed, and that expenses smaller than $10,000 may also be flagged for further review. She testified that invoices for which questions exist are returned to NCS for clarification and/or adjustment. Rippy Rebuttal at 2-4.

Ms. Rippy also clarified that NCS costs that are not specifically allocated to gas or electric operations are allocated in the same way as other common costs. She echoed Mr. Hershberger's direct testimony by noting that the common cost allocation ratios used to apportion costs between gas and electric operations are updated with more current data twice a year. She testified that in the case of NCS charges, common costs are allocated between gas and electric using allocation ratios that are similar to those used to allocate the charge at the NCS level. Rippy Rebuttal at 4.

(d) IG Motion For Involuntary Dismissal. On April 20, 2009, IG filed its Motion for Involuntary Dismissal of Certain Portions of NIPSCO's Case-in-Chief Relating to Allocated Expenses. On May 11, 2009, NIPSCO filed its Response in Opposition. On May 18, 2009, IG filed its Reply In Support of Motion to Dismiss. By Docket Entry dated June 16, 2009, the presiding officers reserved its decision on the motion to this Order.

Having reviewed NIPSCO's case-in-chief testimony, the Commission finds that Petitioner met its evidentiary burden for including NCS charges in NIPSCO's expenses. The gravamen of IG's argument is that NIPSCO failed to include in its evidence exactly how these allocations were made. However, such level of detail is unnecessary to support inclusion of the purported cost in rates. Indeed, as NIPSCO noted in its Reply Brief, no party to this proceeding presented evidence that NCS charges should be disallowed—in fact, just the opposite is true. Even IG's own witnesses supported the inclusion of some level of NCS charges as part of NIPSCO's O&M expense. Accordingly, the Commission finds that NIPSCO met its burden of proof on this issue, and IG's Motion for Involuntary Dismissal is hereby denied.

(e) IG Appeal to Full Commission and Petition to Reopen Record. During the evidentiary hearing, the presiding officers admitted Petitioner's Redirect Exhibits 3 and 3-C ("Redirect Exhibits") into the record over the objection of IG. Those exhibits consisted of the public and confidential portions of NIPSCO's response to IG Data Request Set 15, Question 1. IG appealed the presiding officers' ruling on the admissibility of those exhibits to the full Commission, contending that the exhibits were beyond the scope of IG's cross-examination. IG also requested that the Commission reopen the record to allow additional cross-examination to occur and additional evidence to be presented. The parties submitted briefs to the Commission addressing their respective views on the admission of the exhibits.

Having considered the evidentiary record and the argument and briefing of counsel, the Commission denies IG's appeal with respect to the admission of Petitioner's Redirect Exhibits. The Commission is ultimately charged with evaluating the evidence in this Cause and giving the evidence of record appropriate weight. As noted above, Petitioner submitted sufficient evidence to meet its burden of having these charges considered by the Commission, and the Commission does not give significant weight to the Redirect Exhibits. The information contained within the Redirect Exhibits merely provides the background information for Ms. Taylor's ultimate opinion on the amount of NCS charges that NIPSCO seeks to recover. This information could more appropriately have been provided as workpapers to Ms. Taylor's testimony and exhibits, but were not. Workpapers are not typically admitted into the record, but we find no error in the inclusion of such evidence.

Moreover, IG had ample opportunity to review the information included in the Redirect Exhibits well before the June 30, 2009 hearing and could have cross-examined Ms. Taylor concerning that information. NIPSCO provided IG the data included in the redirect exhibits on March 17, 2009 and NIPSCO responded to additional questions to IG on April 20, 2009. As discussed above, the evidentiary record was sufficient for the Commission to consider NIPSCO's request to include NCS charges as part of its revenue requirement without the Redirect Exhibits. Any objection to the Presiding Officer's admission of additional evidence on that issue goes to the weight of the evidence and not the admissibility. Accordingly, we deny IG's appeal to the full Commission and its Petition to Reopen the Record.

(f) Discussion and Findings.

(i) NCS Allocators. The Commission has previously addressed the recovery of costs allocated from corporate service companies similar to NCS. The Commission evaluates whether the methodology used to allocate costs to the utility is reasonable and produces allocations representative of future costs to be properly allocated to the utility during the period when the rates requested will be effective. *See, e.g,. PSI Energy, Inc.*, Cause No. 42359, at 77.

In this case, NIPSCO Witness Taylor provided testimony supporting the existence of a long-standing methodology for the allocation of costs through NCS, including evidence of the process used to ensure that costs are allocated consistently. Ms. Taylor proposed adjustments to the test year allocations for non-recurring charges and for expenses not appropriate for rate recovery, and NIPSCO conducted further analysis of more than 99% of test year NCS allocations from third-party vendors to identify a proposed representative level of expense. Petitioner's proposed Adjustment OM-17 captured the results of those analyses. While IG Witness Meyer was critical of certain of the Bases of Allocation used by NCS, he offered no evidence that the adjustments proposed by Ms. Taylor or Mr. Hershberger were inaccurate or inappropriate; nor did he offer specific evidence that any of the charges allocated were improper or that the results were not representative of an ongoing level of expense. We find no reason to modify or reject NIPSCO's proposed treatment of NCS charges.

We reject the position of IG that NIPSCO is required to submit evidence justifying each individual expense incorporated into the test year allocations from its service company as a predicate for rate recovery. In the first place, NIPSCO's books are presumptively correct. *Oaktown Tel. Co. v. Miller*, 194 N.E. 741, 742 (Ind. Ct. App. 1935); *West Ohio Gas Co. v. Public Util. Comm'n of Ohio*, 294 U.S. 63, 67-68, 72-73 (1935); *Ind. Mich. Power Co.*, Cause No. 39314, pp. 4-7 (Nov. 12, 1993). Second, the NCS charges are assessed to NIPSCO pursuant to a service agreement properly on file with the Commission. *City of Terre Haute v. Terre Haute Water Works Corp.*, 133 Ind. App. 232, 180 N.E.2d 110, 114-16 (1962). Third, the Commission is very familiar with shared services agreements like that at issue here because most of the major Indiana investor-owned utilities are subsidiaries of holding companies and receive shared services from affiliated service companies just as NIPSCO does.

We have not in the past required the utilities subject to our jurisdiction to provide the level of detail that IG claims is necessary, and we decline to do so here. A theoretical concern about the allocation methodology employed is not sufficient to overcome substantial evidence that the proposed expense is reasonable. *City of Terre Haute*, 180 N.E.2d at 117 (recognizing that the intervenor had the burden of going forward with the evidence after the utility had presented a prima facie case on service company charges). As we have said before, a petitioner's obligation is to submit "substantial evidence" sufficient for a prima facie case, not to satisfy a "clear and convincing" or "beyond a reasonable doubt" standard. *Ind. Mich. Power Co.* at 5. Nor may parties ask the Commission to "manipulate the burden of proof in order to merely disallow portions of [a utility's] rate request." *Id.* at 7. "[T]here is no authority whatsoever to support our imposition of any greater burden of proof than is provided for in a statutory standard or a duly promulgated rule." *Id.* We conclude that the test year NCS allocations, reflected in proposed Adjustment OM-17 are a reasonable representation of annual allocations and should be approved.

(ii) Common Cost Allocators. Similar to our analysis of allocated service company costs, the threshold issue for our consideration is whether the allocation of common costs proposed by Petitioner results in a representative ongoing level of expense. In analyzing the reasonableness of a common cost allocation, we have previously concluded that,

> . . . it is important that the methodology employed (which includes the use of test year ratios) is equitable, yields a reasonable result over time, and is not subject to constant revisions and change. We believe it is important that parties not have the ability to manipulate the allocation of common costs for their own purposes. We realize any allocation formula for any time period is necessarily subject to change but the Commission must use a methodology which proves reasonable over time.

N. Ind. Pub. Serv. Co. [gas], Cause No. 38380, at 6 (Oct. 26, 1988). Our analysis thus reflects the balance between consistency of methodology and accuracy of results.

The record reflects that NIPSCO allocated common costs using a series of common cost ratios developed beginning in 2006 to replace the ratios that had been used for that purpose since 1968. Proposed Adjustment OM-18 adjusted test year common cost allocations to reflect the adoption of the revised ratios in April of 2007. Mr. Hershberger testified that the revised allocation ratios were representative of cost-causation and representative of the way common costs would be allocated on an ongoing basis.

IG Witness Meyer implied that the revised ratios were prepared to justify an increase in expense for NIPSCO's electric business in this case, rather than in an effort to improve the accuracy of the allocation. We disagree. The electric and natural gas industries have undergone sweeping restructuring since the 1960s, so NIPSCO's re-evaluation of the method for allocating common costs was logical, if not required, in light of those changes. While consistency of methodology is desirable over the long run, the result must be an accurate reflection of ongoing expense levels.

We have previously voiced our concern about the manipulation of common cost allocations by parties for their own purposes. *See* Order in Cause No. 38380. Mr. Meyer's proposal to revert to the previous common cost allocators appears to be driven largely by the reduced cost allocation it produces, not by evidence that NIPSCO's revised allocation ratios are inaccurate or non-representative. As Mr. Shambo pointed out, Mr. Meyer's industrial customer clients would potentially experience little of the common costs shifted to the gas operation. As much as Mr. Meyer voiced theoretical opposition to the calculation of NCS Bases of Allocation, his criticism of NIPSCO's proposed allocation ratios is lacking in specificity. In particular, Mr. Meyer recommends the disallowance of $25 million in rate base, but offers no evidence to support the proposition that NIPSCO's proposed capital allocation is not proper.

Based on the evidence of record, we find that the revised common cost allocation methodology employed by NIPSCO is reasonable, produces results that are reflective of ongoing expense levels and properly balances the interests of NIPSCO electric customers and NIPSCO gas customers. We accordingly approve the adjusted test year expense identified in Adjustment OM-18.

(iii) Subdocket Proposal. Having determined that the allocation of common costs and the adjusted test year NCS allocations are reasonable, we find that the creation of a subdocket to this proceeding as proposed by Mr. Meyer unnecessary.

(7) Superfund Remediation Expense. OUCC Witness Pruett recommended the removal of $417,372 in test year remediation expenses associated with NIPSCO's involvement as a Potentially Responsible Party at two Superfund sites. Ms. Pruett asserted the recovery of these costs is not sufficiently related to the provision of public utility service to current or future customers. Ms. Pruett further contended that ratepayers should not be held accountable for management decisions and contractor actions and that the adjustment was appropriate in light of NIPSCO's receipt of insurance reimbursements for some of these expenses. Pruett Direct at 15-18.

In rebuttal, NIPSCO Witness Miller indicated that because NIPSCO has received insurance reimbursement for the Superfund remediation expenses, it did not oppose the adjustment of $417,372 in this particular case. Miller Rebuttal at 35. Mr. Carmichael, in rebuttal, further stated that NIPSCO's decision not to challenge this adjustment did not reflect NIPSCO's agreement with Ms. Pruett's rationale for excluding these costs. More specifically, Mr. Carmichael noted that NIPSCO incurred these costs as a result of providing public utility service to its customers, and that NIPSCO took reasonable steps in selecting its contractors and the facilities used for disposal of generation by-products. Mr. Carmichael concluded by noting that NIPSCO will bear future costs that exceed the insurance received until it files a subsequent rate case, and that NIPSCO has a strong incentive to minimize such costs. Carmichael Rebuttal at 2-7.

Given that there was no dispute as to the appropriateness of the adjustment, we find that resolution of the rationale for the adjustment is unnecessary and accept the OUCC's proposed adjustment.

(8) Midwest ISO Costs in Base Rates. NIPSCO proposed that all Midwest ISO charges be recovered through the RA Tracker and that none be included in base rates. OUCC Witness Catlin adjusted NIPSCO's O&M expenses upward by $5,326,931 to reflect the recommendation of OUCC Witness Satchwell that this level of Midwest ISO Administrative Fees, Schedule 24 charges and Schedule 26 charges be "built into base rates" and removed from the RA Tracker. Catlin Direct at 14. Mr. Satchwell testified that those charges are non-energy related costs that are consistent enough in nature to be accurately reflected in base rates. We see no reason to treat these administrative expenses any differently than we do

for the other Indiana investor-owned electric utilities in Cause Nos. 42359, 43111 and 43306. Therefore, we accept the OUCC's proposed expense adjustment.

(9) Amortization of Deferred Midwest ISO Costs. In Cause No. 42685, NIPSCO was authorized to defer its non-fuel expenses incurred commencing August 1, 2006, in connection with its participation in Midwest ISO. NIPSCO proposed to amortize the deferred costs over a three-year period. This resulted in a pro forma adjustment for deferred Midwest ISO amortization expense of $8,256,052. Miller Direct at 30-31; Petitioner's Ex. LEM-3, Adjustment DA-3.

OUCC Witness Catlin proposed four changes to NIPSCO's claim for deferred Midwest ISO costs. First, Mr. Catlin updated NIPSCO's projection of the balance as of December 31, 2008 to reflect the actual balance of deferred Midwest ISO costs as of that date. Second, Mr. Catlin proposed to amortize the deferred Midwest ISO balance over four years, rather than the three years proposed by NIPSCO. Mr. Catlin stated that a four year amortization period is consistent with the amortization periods used by the other Midwest ISO member utilities in Indiana for such costs. Third, Mr. Catlin proposed to reduce the balance of FERC Assessment Fees based on the average annual level of FERC Assessment Fees paid in 2002 and 2003. Fourth, Mr. Catlin reduced the balance of Midwest ISO costs to account for non-firm transmission revenues received over the period from August 2006 through December 2008. The effect of these four changes is a reduction of $5,386,708 in annual amortization expense for deferred Midwest ISO costs. Catlin Direct at 15-16.

In rebuttal, NIPSCO Witness Miller indicated that NIPSCO agreed with the four-year amortization period and the use of the actual December 31, 2008 balance. Ms. Miller did not agree, however, with the OUCC's proposed reduction in FERC Assessment fees that are part of the deferred Midwest ISO costs or the offset for non-firm transmission revenues. Ms. Miller noted that NIPSCO was authorized to defer the FERC assessment fees in Cause No. 42685, and that the level of such fees increased dramatically when NIPSCO began paying them to Midwest ISO. *Id.* Ms. Miller testified that none of the other utilities have been required to reduce their deferred balances as proposed by Mr. Catlin. As to Mr. Catlin's recommendation to reduce the amount of deferred costs to be amortized by the non-firm transmission revenues, Ms. Miller stated that this was not consistent with the Commission's Order in Cause No. 42685 or the Commission's Order in Vectren South's rate case proceeding (Cause No. 43111). Miller Rebuttal at 37-38. Curtis L. Crum, NIPSCO's Director, Generation Dispatch and Energy Management, stated that NIPSCO believes that it should receive comparable treatment. In addition, NIPSCO was receiving transmission revenues from point-to-point firm and non-firm transmission service prior to joining the Midwest ISO. He explained that the revenues received from the Midwest ISO for point-to-point transmission service are not a result of being a transmission owning member of the Midwest ISO and therefore should not be netted against Midwest ISO administrative charges. Crum Rebuttal at 5. Ms. Miller indicated that the revised amortization expense is $5,732,141, a reduction of $2,523,911. Miller Rebuttal at 37-38.

We find that NIPSCO's rebuttal position is reasonable and proper, and accept NIPSCO's rebuttal adjustment. The Order in Cause No. 42685 allows the deferral of the Midwest ISO costs with no mention of the reduction proposed now by OUCC Witness Catlin. Consistent with our finding that NIPSCO shall eliminate its aging workforce expense following 2012, we find NIPSCO should likewise adjust its base rates to eliminate the Midwest ISO deferred cost amortization at the end of the amortization period.

(10) Amortization of Sugar Creek Deferred Depreciation. In connection with his testimony regarding depreciation expense, OUCC Witness Majoros explained that NIPSCO is requesting a 5-year amortization of $7.3 million of Sugar Creek depreciation expense. Majoros Direct at p 5. Mr. Majoros recommended that the Commission not approve NIPSCO's request for a depreciation expense increase.

As discussed previously, the Commission approved NIPSCO's proposed treatment of depreciation expense, with the exception of decommissioning costs. Accordingly, the Commission approves NIPSCO's treatment of the amortization of deferred Sugar Creek depreciation expense. At the conclusion of the amortization period, NIPSCO shall file a revised tariff removing this amortization from rates.

(11) Rate Case Expense. OUCC Witness Catlin proposed that NIPSCO's rate case expense be amortized over six years, rather than the three years proposed by NIPSCO. Mr. Catlin stated that a longer amortization period was justified due to NIPSCO's high rate case expenses, the infrequency with which NIPSCO has filed rate cases and the inclusion of costs that are not incurred in every case. Mr. Catlin further recommended that, to the extent NIPSCO voluntarily elects to file another rate case before the costs for this case are fully amortized, NIPSCO be required to write off the unamortized balance. Catlin Direct at 16-18.

On rebuttal, Ms. Miller proposed a five-year amortization period. She opposed the proposal that any unamortized portion be written-off if another base rate case is filed. She explained that the energy sector is in a state of transition, the effects of new energy efficiency initiatives are uncertain, and anticipated federal and state legislation may significantly affect costs as well as energy load. As a result, there is a great deal of uncertainty regarding when another base rate case would be required, and it would be inappropriate and unwarranted to punish NIPSCO for filing another rate case within the shorter time frame when it has a statutory right to do so. She explained that the reason for the higher rate case expense was the length of time since NIPSCO's last rate case. Miller Rebuttal at 44-45.

While the rate case expense was approximately $5.9 million, of which of $1.85 million were for legal expenses and $2.51 million were for expert witnesses, no witness testified that the expenses were excessive or imprudent and no parties proposed that any portion of rate case expense be disallowed. The evidence concerning the proposed level of rate case expense incurred by NIPSCO is unchallenged by the parties. Accordingly, the Commission accepts the proposed level of rate case expense and approves a five-year amortization period. However, the Commission accepts the level of rate case expense with an expectation that future cases will provide a higher level of specific detail supporting NIPSCO's (as well as all utilities') proposed rate case expense. Consistent with our finding on the aging workforce adjustment and Sugar Creek depreciation amortization, we find NIPSCO should adjust its base rates to eliminate the rate case expense amortization at the end of the amortization period.

(12) Interest Synchronization. The issue surrounding interest synchronization is derivative of the issue associated with the hypothetical cost of capital discussed previously. The OUCC and IG calculated the interest deduction for purposes of interest synchronization based on the assumption that NIPSCO has debt in its capital structure which it does not have. For the reasons explained with respect to our rejection of the use of a hypothetical capital structure, we reject this proposal with respect to interest synchronization.

E. Pro Forma Present Rates Income Statement. Based upon the evidence presented and the determinations made above, we find that NIPSCO's adjusted operating results under its present rates and charges for electric utility service are as follows:

Description	Amount
Operating Revenue	$ 1,482,439,820
Fuel, Purch. Power and Related URT[16]	526,936,766
Gross Margin	$ 955,503,054
Operations & Maintenance Expenses	$ 338,056,493
Depreciation Expense	193,989,102
Amortization Expense	27,699,199
Taxes Other Than Income	56,208,081
Income Taxes	114,340,190
Total Operating Expenses	$ 730,293,065
Net Operating Income	$ 225,209,989

In summary, we find that with appropriate adjustments for ratemaking purposes, NIPSCO's annual net operating income under its present rates for electric utility service would be $225,209,989. When compared to the return determined in Section 8(B)(5), *supra*, NIPSCO's pro forma NOI exceeds what is necessary to obtain that return. Accordingly, we find that Petitioner's present rates are unreasonable and unlawful.

10. Authorized Revenue Requirement. On the basis of the evidence presented in these proceedings, we find and order that NIPSCO shall be directed to decrease its rates and charges for electric utility service to produce gross margin of $899,401,890 as follows:

[16] Includes $11,015,038 of non-trackable fuel expense.

Description	Amount
Operating Revenue	$ 1,433,561,560
Fuel, Purch. Power and Related URT[17]	534,159,670
Gross Margin	$ 899,401,890
Operations & Maintenance Expenses	$ 337,862,056
Depreciation Expense	193,989,102
Amortization Expense	27,699,199
Taxes Other Than Income	55,424,442
Income Taxes	92,001,559
Total Operating Expenses	$ 706,976,357
Net Operating Income	$ 192,425,533

11. Revenue Allocation.

A. Retail Cost of Service Study.

(1) Evidence. NIPSCO presented the results of its retail cost of service studies, prepared by Robert D. Greneman of Shaw Consultants International, Inc. (formerly Stone & Webster Management Consultants, Inc.). Mr. Greneman explained that a fully-allocated cost of service study, which apportions the Company's revenue requirement to customer classes, provides a standard industry yardstick to measure the degree to which the revenues produced by each customer class, in comparison with the cost to serve that class, are equitable and non-discriminatory.

He stated that NIPSCO's cost of service study developed a revenue requirement for each customer class based on a target rate of return for that class; developed a fully unbundled pro forma revenue requirement for each defined function (generation, transmission, distribution and billing and collecting) as well as sub-functions within each of these main functions based on the target rate of return for each class; indicated which customer classes are receiving or providing a subsidy to other classes; and developed unit costs by customer class and unbundled function.

Mr. Greneman explained that the cost of service study was developed on a gross margin basis, i.e., net of fuel and purchased power, as the Company is proposing to recover all of its fuel through its FAC and all purchased power costs through its RA Tracker. The cost of service study used the traditional three-step approach that consists of functionalization, classification and allocation. He stated that production plant was separated into fixed and variable components to capture fixed costs associated with generating plant versus non-fuel variable costs such as fuel

[17] Includes $11,015,038 of non-trackable fuel expense.

handling, boiler maintenance and fuel stock. He stated that the breakdown was based on a fixed-variable analysis that was performed by the Company.

Mr. Greneman testified that primary lines, secondary lines and line transformers were classified as 100% demand-related because NIPSCO's property records were not sufficiently detailed as to reliably support a zero-intercept or minimum system analysis. Plant and expenses functionalized to the generation functions were allocated on the basis of the contribution of each class of service to the four-month (June through September) average control area peak (hereinafter referred to as a "4 CP methodology"). Mr. Greneman stated that transmission was allocated among retail customers based on the 12-month average of the Company's coincident control area peak demands (hereinafter referred to as a "12 CP methodology"), which is the most commonly used method before the FERC. He noted that a 12 CP methodology rather than a 4 CP methodology is used by Midwest ISO for cost allocation.

Nicholas Phillips, Jr., a principal in the firm of Brubaker & Associates, Inc., testified on behalf of the IG and made certain recommendations to NIPSCO's cost of service study. He asserted that production and transmission investment should be allocated by the 4 CP methodology because it properly allocates cost responsibility to customer classes and, if implemented properly, would minimize the need for new generating capacity. Mr. Phillips criticized Mr. Greneman's classification of a significant amount of production non-fuel expense as being variable and energy related. He stated that, based on a review of other utilities in Indiana, he recommended that NIPSCO use 90% fixed and 10% variable classifications for production related non-fuel operation and maintenance expense. Phillips Direct at 14-15. Mr. Phillips also expressed a concern regarding direct assignments of costs associated with items such as sales expense and customer information related expense. He admitted on cross-examination, however, that were these costs not directly assigned, they would be borne by other customers. Tr. KK-22-23. Mr. Phillips stated that customers served at 34.5 kV should not be allocated costs associated with standard primary voltage because these customers do not use these lower primary voltage lines and substations. Phillips Direct at 17-18. Mr. Phillips did not agree with NIPSCO's proposal to remove the cost of fuel from its base rates. Phillips Direct at 18.

Dale E. Swan, senior economist and principal with Exeter Associates, Inc., addressed issues involving Petitioner's embedded class cost of service study on behalf of the OUCC. Dr. Swan disagreed with Petitioner's allocation of its generation and transmission plant-related costs. Swan Direct at 3. He disagreed with the way in which generation and transmission capital costs and generation and transmission plant-related O&M costs have been allocated in Petitioner's study, specifically noting that these costs have largely been allocated on a peak demand basis, with no responsibility being assigned to energy. Swan Direct at 5. Dr. Swan disagreed with Petitioner's classification and allocation of production and transmission plant related costs as 100% peak demand related. He stated that a cost study should classify and allocate costs among customer classes on the basis of other factors that caused those costs to be incurred and that Petitioner's total production and transmission plant investment costs have not been caused solely by the peak demand of its customers. Swan Direct at 7. Dr. Swan opined that a significant portion of the investment costs have been directly caused by the need to meet the energy requirements of Petitioner's customers so a commensurate portion of the investments costs and the associated plant-related O&M costs should be allocated on the basis of class energy usage. Swan Direct at 7. Dr. Swan recommended use of the OUCC's Peak and Average Cost of Service

Study as the cost basis for determining the spread of the allowed change in jurisdictional revenues. Swan Direct at 3. He opined that the Peak and Average method allocates a portion of plant and related expenses on the basis of class contributions to the relevant measure of system coincident peak demand, and the remainder on the basis of class energy use at source. Swan Direct at 17. Based on the results of his analysis, Dr. Swan recommended that 65% of production plant and related O&M costs be allocated on class energy use, and the remaining 35% be allocated on each class' contribution to the appropriate measure of peak demand. Swan Direct at 20. As an alternative to the use of the OUCC's Peak and Average study, Dr. Swan recommended use of the 12 CP study that was used in NIPSCO's last rate case rather than use of the Company's proposed 4 CP methodology for production plant. Swan Direct at 32. Dr. Swan opined that the 12 CP methodology is superior to the 4 CP methodology. *Id.*

Kerry A. Heid testified on behalf of Intervenor MU. Mr. Heid provided a comprehensive overview of the history of NIPSCO's rates, including NIPSCO's last base rate proceeding and the Commission investigation into NIPSCO's rates in Cause Nos. 38045 and 41746. Heid Direct at 4.

He explained that the classification of costs as demand, energy or customer-related has significant impact on the allocation of costs. For example, costs classified as energy-related have the most favorable impact on residential customers, while costs classified as customer-related have the least favorable impact on residential customers. Mr. Heid agreed with NIPSCO's 4 CP demand allocation for production plant. He noted that the FERC allocation method states that if the demand curve is relatively flat then use of 12 CP is appropriate and, if there is a pronounced peak, then use of another CP method is supported. He noted that Mr. Greneman utilized the FERC allocation method to conclude that the use of 4 CP was supported. *Id.* at 8. He noted that Vectren South, in Cause No. 43111, used 4 CP production demand allocation and that in PSI's last general rate case, the Commission noted that PSI's demand allocation methodology "is also consistent with the FERC's allocation guidelines." *PSI Energy, Inc.*, Cause No. 42359, at 101.

Mr. Heid disagreed with NIPSCO's fixed-variable analysis and NIPSCO's proposed allocation of production O&M accounts. Mr. Heid recommended that the Commission reject NIPSCO's fixed-variable analysis and suggested that all production expenses should be classified as demand-related, "as they were in previous rate cases." Heid Direct at 9-11.

Mr. Heid explained that line losses are losses that occur in the utility's system between the generating or purchased power sources and the customers' meters. He stated that Mr. Greneman used a 1999 line loss study prepared by NIPSCO Transmission Planning and asserted that there was a subsequent 2001 line loss study. Heid Direct at 12. Mr. Heid recommended that the Commission reject the 1999 line loss estimates and use the line loss percentages that were filed by NIPSCO in Cause Nos. 41746 and 41658.

Mr. Heid also disagreed with Mr. Greneman's assertion that there are inadequate records to perform a zero-intercept analysis, citing the historical use zero intercept analyses in Cause Nos. 41746 and 38045. Mr. Heid noted that the NARUC Electric Utility Cost Allocation Manual supports the appropriateness of classifying a portion of distribution costs as customer-related. He recommended that NIPSCO modify its cost of service study to reflect the minimum distribution system analysis results from Cause No. 41746.

IG Witness Phillips' cross-answering testimony responded to the Peak and Average method proposed by OUCC Witness Swan. He stated that Dr. Swan's proposal inappropriately over-allocates production plant costs to high load factor and off-peak classes, is counter to the Commission's direct findings on this issue, is not based on sound rate making principles and should be rejected. Mr. Phillips concluded the Commission should also reject Dr. Swan's alternative proposal to adopt a 12 CP allocation method for production and transmission fixed costs. He argued that instead, the Commission should adopt the 4 CP methodology proposed by the Company because the latter method more accurately reflects the dominant system peak demands that drive incremental generation investments on the NIPSCO system.

In rebuttal, Mr. Greneman and Mr. Shambo addressed Mr. Phillips' proposed 90% fixed/10% variable allocation of non-fuel O&M expenses and Mr. Heid's proposal that non-fuel O&M expenses be 100% fixed. Mr. Greneman and Mr. Shambo explained that for its rebuttal position, NIPSCO would support the 90% fixed/10% variable allocation of non-fuel O&M expenses as recommended by Mr. Phillips. Mr. Greneman asserted that Mr. Heid had not presented any technical evidence to discredit the line loss percentages calculated from the 1999 loss study, and he recommended that the loss percentages used in the cost of service study in this proceeding should stand. With respect to Mr. Phillips' contention that NIPSCO over-assigned sales expenses and customer service and informational expenses to industrial customers, Mr. Greneman noted that NIPSCO has one of the largest industrial bases of any utility in the country and has individuals dedicated to providing needed billing, sales and customer service and informational expenses for these industrial customers. He explained that, if the industrial class is not directly allocated these dedicated costs, then other classes, such as residential, will be asked to provide a subsidy to industrial customers, which is not in accordance with cost causation principles.

(2) Discussion and Findings. Witnesses Heid and Phillips agreed with and relied upon Mr. Greneman's application of the FERC guidelines to determine that a 4 CP method is the appropriate basis for allocating production plant costs among NIPSCO's customer classes. We find this reliance is misplaced. While we are not bound to directly apply the FERC Allocation Method Tests for retail ratemaking in Indiana, we find the guidelines useful information for determining the appropriate production cost allocation methodology. In *Golden Spread Elec. Coop. v. Sw. Pub. Serv. Co.,* 123 F.E.R.C. p .61,047 at 61,249, FERC stated,

> Historically, the Commission has considered three tests in determining whether a system is better characterized as 3 CP or 12 CP. First, the Commission compares the average of the system peaks during the purported peak period, as a percentage of the annual peak, to the average of the system peaks during the off-peak months, as a percentage of the annual peak -- the On and Off Peak test. *Generally, the Commission has held that a nineteen percentage point or less difference between these two figures supports using the 12 CP method.* The second test, the Low-to-Annual Peak test, involves the lowest monthly peak as a percentage of the annual peak. *The Commission considers a range of sixty-six percent or higher as indicative of a 12 CP system.* The third test is the Average to Annual Peak test, and it computes the average of the twelve monthly peaks as a percentage of annual peak. *Generally, the range for a utility to be considered 12 CP is eighty-one percent or higher.*

(Emphasis added, internal citations omitted.)

The results for NIPSCO appearing in Petitioner's Exhibit No. RDG-2, Schedule 1.0, page 3 of 3 for Test 1 are 19% and 16% for 2007 and 2006, respectively; a six-year average 68.5% for Test 2; and a 6-year average of 81.0% in the last test. We therefore find that application of the FERC Allocation Method Test could reasonably support a finding that a 12 CP method is more appropriate for NIPSCO system load characteristics, rather than the 4 CP method determined by Mr. Greneman. Moreover, this Commission previously has found that the "12 CP method is often utilized to reflect the full range of operating realities throughout the year including system demand, scheduled maintenance, and reserve requirements." Cause No. 39314, at 171. In the most recently contested electric utility rate proceeding, we noted in our Order that "a change in cost allocation methodology can have significant impacts on customer classes, and, thus, such a change should not be lightly undertaken, especially where, as here, so much of PSI's plant was in service at the time of its last rate case and costs were assigned using the 12-CP methodology in that case." Cause No. 42359 at 102. Here, the record indicates that NIPSCO's current rates reflect a 12 CP methodology as approved in Cause No. 37023, and adjusted across-the-board in Cause No. 38045, and any departure can have significant impacts and should not be undertaken lightly. We note the complete absence of any analysis of other operating realities, such as loss of load probabilities, reserve requirements, and scheduled maintenance by the proponents of a change to 4 CP method that would provide sufficient evidence to justify a change in allocation method.

After considering the evidence, we find that allocation of these costs shall be based on the 12 CP methodology. Much of the capital investment costs at issue were, in fact, incurred to meet NIPSCO's energy requirements at lower costs thereby minimizing the total cost of service. This is consistent with the evidence that NIPSCO's system was designed, planned, and built in material part to serve the loads of its energy intensive industrial customers. Moreover, we note that the most recent capacity addition to the NIPSCO system was the intermediate/baseload combined cycle Sugar Creek facility, and not a "peaker" generating plant.

This Commission has a long and consistent practice of allocating generation and transmission costs on some measure of coincident peak and precedent must factor into our final decision. Given that our last Order found the 12 CP methodology appropriate, and the FERC tests demonstrate the 12 CP is marginally still appropriate, we find no reason to move to a different allocation methodology in this Cause. Moreover, our preference is to utilize the previously approved allocation methodology, given sufficient evidence, unless system operating characteristics are demonstrated to have changed since the last approved cost of service study allocation methodology.[18] Accordingly, we direct NIPSCO to utilize a 12 CP study as the initial basis on which to determine class revenue responsibilities.

We also find that NIPSCO's initial proposal to split non-fuel Production O&M expenses as 60 percent variable and 40 percent fixed will result in a superior reflection of the costs of serving the several customer classes. We are particularly persuaded by the fact that this split is consistent with both the FERC and the NARUC methodologies. Thus, despite the Company's willingness to revise its study to comport with Mr. Phillips proposed 90%/10% split, we order NIPSCO to utilize its initially proposed 60%/40% split for non-fuel Production O&M expenses.

[18] *See, Ind. Mich. Power Co.*, Cause No. 39314, at 171-72 (Nov. 12, 1993).

With regard to NIPSCO's line loss study, while we find it troubling that Mr. Greneman was unable to explain the differences from the 1999 line loss study and the results submitted into evidence in Cause No. 41746, the only evidence that we have in this proceeding are the 1999 results, and therefore we find that those results are sufficient for purposes of this proceeding. With regard to Mr. Heid's recommendation that NIPSCO modify its cost of service study to reflect the minimum distribution system analysis results from Cause No. 41746, the Commission would note that those results are not in evidence in this case; the preparers of that analysis were not subject to cross-examination; and we must base our decisions upon substantial evidence in the record. Based upon those factors, and the arguments raised by Dr. Swan against the use of a minimum system approach, the Commission finds that NIPSCO need not modify its cost of service study to reflect the minimum distribution system analysis.

With regard to Mr. Phillips' contention that NIPSCO over-assigned sales expenses and customer service and informational expenses to industrial customers, we find that it would be inappropriate to allocate those direct expenses to other rate classes, and we therefore find that NIPSCO's direct allocation of those costs is appropriate.

While various witnesses questioned NIPSCO's billing determinants, in rebuttal, Mr. Greneman explained that NIPSCO prepared an analysis of its present rates under pro forma billing determinants that produce pro forma revenues, before NIPSCO's proposed rate increase. He noted that neither Mr. Phillips nor Mr. Heid contested NIPSCO's reconciliation of demand billing determinants on technical grounds.

In conclusion, the Commission finds that NIPSCO should rerun its cost of service study at the allowed total jurisdictional revenue requirement based on a 12 CP allocation of both generation and transmission costs and reflecting the original 60/40 variable/fixed split of non-fuel production O&M expenses, and the results of that cost of service study should be utilized as the starting point from which to recover from the several customer classes the revenue requirement found above. NIPSCO shall file the results of the cost of service study as a component of its compliance filing ordered *infra.*

B. Reduction in Subsidy/Excess Revenues.

(1) Evidence. In its direct case, NIPSCO's proposed moderation plan impacted all classes that were increasing, including its residential customers and inter-departmental sales. As discussed earlier in this Order, much testimony was presented concerning the appropriate level of pro forma operating revenues at present rates. As found hereinabove, NIPSCO's rebuttal presentation of the revenue credit ($55 million at present rates) and expiring special contracts ($80 million at present rates) was approved. Mr. Shambo, in rebuttal, discussed the issue of how pro forma revenues at current rates impacts NIPSCO's proposed rates due to its moderation plan, which proposed to limit the subsidy reduction to any customer class to 25%. Mr. Heid noted that NIPSCO proposed elimination of only 25% of the interdepartmental sales subsidies. Heid Direct at 31. He recommended that the Commission order NIPSCO to eliminate 100% of the NIPSCO inter-departmental subsidies. On rebuttal, NIPSCO concurred with Mr. Heid's recommendation.

Mr. Phillips asserted that NIPSCO's rate moderation plan did not take into account increases to its largest customers due to the elimination of special contracts. Phillips Direct at 34. Mr. Phillips recommended that the large industrial rates be based on parity or without subsidies and, to the extent other classes can be moved to cost of service, he recommended that be accomplished to the extent practicable. Phillips Direct at 34-35. Mr. Shambo responded in rebuttal that Mr. Phillips' comments regarding a lack of moderation to special contract customers ignored that under the terms of the special contracts, any rates approved in this proceeding would not become effective for these customers until six months after a Commission order in this proceeding. In other words, Mr. Shambo argued that these customers anticipated and contractually agreed to the method of instituting a grace period between the effective date of a Commission order in the rate case and the impact of those new rates on them. Thus, Mr. Shambo concluded that these customers will receive the benefit of their contractual moderation plan.

(2) Discussion and Findings. All parties in this proceeding have a vested interest in how to allocate the revenue requirement across the customer segments. We initially note that our decision to use a 12 CP cost allocation methodology serves to assign more costs to the energy intensive industrial customers than the company's proposed 4 CP methodology would have allocated. As such the use of the 12 CP cost allocation methodology can be viewed as a moderating step to the rates that will be borne by low energy intensive customers. We are also cognizant that NIPSCO's managerial decision to discontinue the use of special contracts effectively imposes an increase in rates on some of its energy intensive industrial customers and that any proposed subsidy moderation scheme will further increase their rates. These factors lead to a conclusion that basing rate class revenue requirements on a 12 CP allocation methodology and an equalized, or parity, rate of return balances the regulatory principles of gradualism and rates based to the extent practical on the cost to serve customers. Accordingly, based upon the evidence presented, we find that NIPSCO's proposed 25% moderation plan is not approved and rates shall be designed on a parity return basis.

12. Rate Design.

A. Tracking Mechanisms.

(1) Fuel Adjustment Charge.

(a) Evidence. NIPSCO proposed to remove fuel-related costs from its basic rates. Mr. Shambo noted that this Commission has repeatedly encouraged electric utilities to purchase power from neighboring utilities when such power was less expensive than that of the utility's own internal generating units.[19] He explained that in this proceeding NIPSCO proposed to remove all fuel costs,[20] including purchased power costs, from its base rates for two reasons: (1) fuel is a variable cost by nature and should not be collected in a fixed component on the bill; and (2) to simplify its tariff structure. As discussed later in this Order, NIPSCO also proposed to remove purchased power and related Midwest ISO costs from the FAC and recover these costs through the RA mechanism.

OUCC witnesses Michael Eckert, Satchwell, Cearley and IG witness James Dauphinais all opposed NIPSCO's removal of all fuel costs from base rates. Mr. Dauphinais testified, for

[19] *N. Ind. Pub. Serv. Co.*, Cause No. 37343, at 4-5 (Dec. 27, 1983). (The Commission found that "it is imperative that [NIPSCO] . . . commence a program directed toward reducing fuel costs by supplementing internal coal generation of electricity with the purchase of less expensive supplies of electricity from neighboring utilities whenever operating conditions will permit this without adversely affecting the reliability of electrical services.")
[20] Except for non-trackable fuel expense of $11,015,038.

example, that NIPSCO had not shown that it is reasonable to move the recovery of purchased energy costs from base rates and its FAC to its proposed RA Tracker. Dauphinais Direct at 7. Mr. Phillips recommended that NIPSCO's rates maintain the test year fuel cost as the base cost of fuel in the approved rate structure and that the FAC should be modified to more accurately adjust fuel cost by class with different FAC adjustments for each class reflective of fuel cost. Mr. Phillips proposed that the Commission adopt the FAC allocator methodology proposed in Cause No. 43618 in this proceeding. Phillips Direct at 31. In its cross-answering testimony, the OUCC opposed this recommendation. Swan Cross-Answering at 10-11.

In rebuttal, Mr. Shambo responded to Mr. Phillips' suggestion that NIPSCO incorporate its FAC allocator proposal from its pending DSM proceeding (Cause No. 43618) into this proceeding by acknowledging that while NIPSCO continued to support the FAC allocator proposal, it had agreed with the other parties in Cause No. 43618 to stay the consideration of that proposal. Mr. Shambo stated that NIPSCO understood that parties have raised certain questions regarding the application of a voltage differentiated line loss factor, and NIPSCO agreed that some methodology should be used to recognize the differences in fuel cost to the customer segments based upon the voltage level of service. Therefore, Mr. Shambo articulated NIPSCO's agreement to apply the 1999 line loss factors used by Mr. Greneman in this proceeding in its FAC filings subsequent to an order in this proceeding.

(b) Discussion and Findings. The non-NIPSCO parties in this proceeding opposed NIPSCO's proposal to remove all fuel costs from its base rates. They articulated two sound reasons for this opposition: (1) NIPSCO's proposal is different than the traditional treatment of electric utility fuel costs at the Commission and would result in treatment different from all the other electric utilities in the State of Indiana; and (2) NIPSCO's proposal does not consider differences in line losses at various voltage levels. Whether or not NIPSCO can address the second concern by applying the line loss factors in the subsequent FAC filings, the present record lacks sufficient evidence to support how this would be accomplished. Further, as noted above, we are troubled by the line loss study presented herein and are not convinced such a study can reasonably and cost-effectively reach the level of detail needed for application to a monthly fuel cost allocation.

As for the traditional treatment of fuel costs, the Commission would note that fuel is an integral component of electricity production and is appropriate to establish in base rates at the same time all the other costs of electricity production are established. The Commission would further note that the Indiana statutory construct does not mandate or support fuel costs embedded into base rates; rather, it provides for the ability of electric generating utilities to track the changes in fuel costs. Under this construct, absent the tracking of changes from base rates, fuel costs would remain statically embedded in base rates. While providing accurate price signals to one's customers is a laudable goal, nothing in NIPSCO's proposal to recover all trackable fuel costs in its FAC provides a different price signal to customers because total bills would remain identical in either approach. Based upon the evidence presented, the Commission finds that fuel costs should be included in NIPSCO's base rates and its FACs should recover changes in trackable fuel costs. This treatment takes into account different customer classes' voltage levels to the extent historically practical.

(2) Petitioner's Proposed RA Tracker.

(a) NIPSCO's Evidence. Mr. Crum discussed certain aspects of NIPSCO's RA Tracker, which was requested pursuant to Ind. Code § 8-1-2-42(a). NIPSCO Witness Miller described the proposed timing for RA filings and pro forma schedules for processing the RA Tracker.

Mr. Crum testified that the RA Tracker provides for the timely recovery of: (1) charges and credits assessed by RTOs, including costs associated with transmission upgrades constructed by others ("RTO Costs"); (2) NIPSCO's purchased power costs; (3) NIPSCO's capacity costs; and (4) the allocation of revenues from NIPSCO's OSS. Mr. Crum described the Midwest ISO-related costs incurred by NIPSCO. He stated NIPSCO's Midwest ISO-related costs can be grouped into three categories: (1) non-fuel charges assessed by the Midwest ISO pursuant to its tariff that has been accepted for filing by FERC; (2) fuel-related costs incurred due to participation in the Midwest ISO pursuant to its tariff that has been accepted for filing by FERC; and (3) transmission costs accessed through Attachment FF and other transmission costs pursuant to rate schedules that have been accepted for filing by FERC.

He stated the current RTO Costs that would be included in the RA include: (1) Midwest ISO administrative costs billed under Schedule 10 (ISO Cost Recovery Adder), a successor provision (including Schedule 10-FERC), or any successor tariff of the Midwest ISO; (2) Midwest ISO administrative costs billed under Schedule 16 (Financial Transmission Rights Administrative Service Cost Recovery Adder), or any successor tariff of the Midwest ISO; (3) Midwest ISO costs associated with purchased power such as Non-Asset and certain Asset Energy Amounts; (4) Midwest ISO administrative costs billed under Schedule 17 (Energy Market Support Administrative Service Cost Recovery Adder), or any successor tariff of the Midwest ISO; (5) Midwest ISO costs and revenues that are "socialized," which are often referred to as "uplift costs," such as the Real-Time Revenue Neutrality Uplift Amount; (6) certain Midwest ISO transmission costs assigned to NIPSCO pursuant to the Midwest ISO's Open Access Transmission and Energy Markets Tariff ("TEMT") including, but not limited to, Schedule 24 and Schedule 26; (7) fuel-related Midwest ISO amounts related to Revenue Sufficiency including (i) Day-Ahead Revenue Sufficiency Guarantee Distribution Amount; (ii) Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount; and (iii) revenue sufficiency make whole payments; (8) transmission revenues from Midwest ISO Schedules 7 and 8 and the revenues from Midwest ISO Schedules 1 and 2 associated with Schedules 7 and 8; (9) costs and revenues from transmission adjustments captured in the Midwest ISO Schedule 11; and (10) any other amounts billed pursuant to the Midwest ISO's tariff that have been approved for filing at FERC and that are not included in NIPSCO's FAC proceedings.

Mr. Crum explained the recovery of Midwest ISO costs in the RA Tracker should be approved for the following reasons: (1) the Midwest ISO charges and credits to be recovered under the RA Tracker are assessed pursuant to the Midwest ISO's tariffs and are a necessary cost as NIPSCO continues to provide safe, adequate, and reliable service to its customers; (2) the costs associated with purchased power are reasonable and necessary for the provision of safe, adequate, and reliable service to the Company's customers; (3) the RTO Costs and purchased power costs are variable in amount from year to year and quarter to quarter; (4) the timing of these charges and credits is also variable; (5) the RTO Costs are also substantial in the aggregate and in individual amounts; and (6) the ability to timely recover Midwest ISO charges on an ongoing basis is important to NIPSCO's financial well being and to the accuracy of price signals sent to the Company's customers.

Mr. Crum explained NIPSCO's proposed recovery of purchased power costs. Mr. Crum stated that in the past purchased power costs have been recoverable in the FAC, subject to a "benchmark," which was utilized as a surrogate for the fuel component of the costs. In this proceeding NIPSCO proposed to include its purchased power costs in its RA Tracker, subject to a benchmark.

Mr. Crum described NIPSCO's proposed Purchased Power Benchmark. He explained that each day a "Benchmark" would be established based upon a generic Gas Turbine ("GT"), using an effective GT heat rate of 12,500 btu/kWh and a fuel cost based on the day ahead natural gas prices for the New York Mercantile Exchange Chicago City Gate, plus a $.17/ mmbtu gas transport charge. Purchases made in the course of the Midwest ISO's economic dispatch regime to meet jurisdictional retail load are a reasonable expense and are fully recoverable up to their actual cost or the Benchmark, whichever is lower. In each individual hour that purchased power costs exceed the Benchmark, purchases made under the following conditions would be recoverable: (1) If NIPSCO has generating units available to the Midwest ISO that were offered into the Midwest ISO market at expected cost and which were not selected by the Midwest ISO and the utility purchased power over the benchmark, 100% of the purchase power costs are recoverable; (2) if the sum of unplanned full forced outages, qualifying environmental derates, partial outages, and qualifying scheduled maintenance outages total 11% or more of NIPSCO's seasonal generating fleet capacity, 100% of purchase costs over the Benchmark for purchases made to account for such outage level are recoverable; (3) if purchases were made to account for qualifying environmental derates, 100% of the purchase costs over the Benchmark for such purchases are recoverable up to the amount of the derated capacity; (4) for purchases not subject to 100% recovery as described in the above parameters, 85% of the purchase costs over the Benchmark for such purchases are recoverable up to the FERC approved Midwest ISO definition of scarcity pricing. Mr. Crum explained that the Midwest ISO makes the decision which NIPSCO generating resources are to be dispatched and at what level. Depending on the specific conditions, the Midwest ISO's directive may be for NIPSCO to purchase power from the market rather than the Midwest ISO calling for NIPSCO's internal generation. As a result, NIPSCO may, on occasion, be directed by the Midwest ISO to make economy purchases at what may appear to be a higher cost than NIPSCO's own resources. Those Midwest ISO directed purchases can even be at levels above the Benchmark. Mr. Crum testified the Benchmark mechanism is in the public interest. He stated use of a daily Benchmark captures the variability of fuel prices over time. In addition, the Benchmark addresses the recoverability of costs incurred when the Midwest ISO elects to utilize other more cost efficient generation in the footprint in lieu of starting higher cost NIPSCO generation, benefiting NIPSCO's jurisdictional retail customers.

Mr. Shambo testified that excluding purchased power costs from the FAC is consistent with the logic of the Revised Purchased Power Benchmark approved in NIPSCO's FAC71 sub-docket, which allowed for recovery of certain purchased power costs via a tracker mechanism approved pursuant to Ind. Code § 8-1-2-42(a).

NIPSCO also proposed to recover prudently-incurred capacity costs, which were described by NIPSCO Witness Sweet. Mr. Sweet testified that he was familiar with the evolution of the Midwest ISO's long-term Resource Adequacy Plan. He stated that when FERC conditionally approved TEMT on August 6, 2004, it also approved the proposed Module E of the TEMT as a "short-term transition mechanism" to help ensure reliability throughout the Midwest

ISO footprint. In the same order, FERC directed the Midwest ISO to work toward a long-term resource adequacy plan through its stakeholder process. In response to that directive, on December 28, 2007, the Midwest ISO filed its long-term resource adequacy proposal, which contained mandatory requirements for any market participant serving load in the Midwest ISO region to have and maintain access to sufficient planning resources. Under the proposal, the Midwest ISO would establish a Planning Reserve Margin for each Load-Serving Entity ("LSE"), which then must demonstrate that it has sufficient resources to meet the forecast requirements plus the applicable Planning Reserve Margin requirements. Mr. Sweet explained that NIPSCO is an LSE and, therefore, must comply with these requirements.

The first planning year under the Resource Adequacy Plan started June 1, 2009. Mr. Sweet testified that NIPSCO is a member of the Midwest Planning Reserve Sharing Group ("PRSG"), which is a voluntary group of LSEs. He explained that the PRSG was established to study the collective resources of the group and to determine a minimum level of planning reserve requirements. He stated that the Midwest PRSG approved a planning reserve target margin for the 2008-2009 planning year of 14.3% for the Central Zone, of which NIPSCO is a member. He testified that NIPSCO purchased 800 MWs of capacity for the period June 1, 2008 through May 31, 2009 and entered into seven contracts of between 50 and 200 MWs each for a total price of under $14,000,000. He stated that NIPSCO proposed to recover its 2009 capacity costs through the RA Tracker.

The final item included in the RA Tracker is the gross margin from OSS. As discussed earlier herein, NIPSCO proposed that 100% of future OSS margins up to $15 million annually will be passed back to the ratepayers through its proposed RA Tracker.

(b) OUCC's Evidence. OUCC Witnesses Satchwell and Eckert opined that purchased power costs and fuel-related Midwest ISO charge types should be tracked in the FAC. Mr. Eckert recommended that the Day-Ahead Revenue Sufficiency Guarantee ("RSG") Distribution Amount and the Real-Time RSG First Pass Distribution Amount charge types remain in the FAC and that Day-Ahead and Real-Time RSG Distribution Amounts associated with native load be included in the FAC and charges associated with non-native load should be included in the OUCC's proposed RTO Tracker. Mr. Eckert also recommended that only Revenue Sufficiency Guarantee Make Whole Payments ("MWP") Amounts associated with native load be recovered through the FAC. RSG MWP Amounts associated with non-native load should be recovered through the OUCC's proposed RTO Tracker where OSS margins are recovered. They agreed that NIPSCO's purchased power costs should be subject to NIPSCO's proposed benchmark as revised by Mr. Eckert. Mr. Eckert recommended that NIPSCO continue to proactively track RSG amounts above the benchmark and provide support for proposed recovery of such charges as a narrative in its testimony filed in each of NIPSCO's future FAC and/or RTO tracker filings. He also asked the Commission to require NIPSCO to include a narrative in testimony providing evidence of the reasonableness of Contestable RSG amounts.

Mr. Satchwell acknowledged that the OUCC generally supports participation in RTOs as they are supposed to provide benefits to customers. He asserted that utilities must balance benefits with costs. Satchwell Direct at 3-4. He stated that the OUCC is concerned that NIPSCO is proposing open-ended approval of all current and future Midwest ISO costs and revenues. Satchwell Direct at 4. He asserted that it is unclear how NIPSCO proposes to recover any future modified or new Midwest ISO charge types and concluded that these changes should be reviewed and a new determination of appropriate recovery made. Satchwell Direct at 4-5. He testified that NIPSCO should include the test year amount of Midwest ISO charges and credits under Schedules 10, 10-FERC, 16, and 17 in base rates ($6,502,782) and track variances through the RA. Satchwell Direct at 6. He also suggested that NIPSCO should build test year amount of Schedule 24 (load-balancing authority) charges and credits in base rates ($1,287,485) and track variances through the RA Tracker. Satchwell Direct at 7. He further concluded that NIPSCO should include pro forma period amount of Schedule 26 charges ($111,634) into base rates and track the variance through an RTO tracker. Satchwell Direct at 8. He stated that the OUCC accepted NIPSCO's proposal to include non-Regional Expansion Criteria and Benefits transmission revenues as an offset in base rates without tracking variances. Satchwell Direct at 8.

With regards to recovery of purchased capacity costs, Mr. Satchwell testified that NIPSCO should be allowed to recover prudently-incurred capacity costs through a tracker, subject to prudency reviews at each tracker filing. He recommended that NIPSCO should be required to justify any capacity purchases that yield a planning reserve margin greater than Midwest ISO's. Satchwell Direct at 13-14. He stated that Midwest ISO's 12.69% planning reserve margin varies greatly from NIPSCO Witness Sweet's statement of a 15% margin and that NIPSCO's planning reserve margin should be clarified so as to avoid incurring Module E penalties. Satchwell Direct at 13. He also recommended that Module E penalty charges should not be recoverable in the RA Tracker.

Mr. Satchwell expressed two additional concerns regarding the RA. First he testified that quarterly filing would present many challenges for review and auditing and second, he observed that the RA Tracker appears to be a "catch-all" for recovery of many costs and revenues which may significantly decrease transparency and lead to inaccurate price signals. Satchwell Direct at 19. To address these concerns, Mr. Satchwell proposed that Midwest ISO costs and revenues and the OSS sharing be included in one tracking mechanism that he designated the RTO Tracker and that purchased capacity costs should be combined into a separate tracking mechanism that he designated as the Resource Adequacy Tracker. He recommended that the RTO Tracker should be a semi-annual tracking mechanism, coordinated with FAC audit process and that the OUCC and Intervenors should have 60 days to audit and that the Resource Adequacy Tracker should also be a semi-annual tracker, subject to 60-day audit. Satchwell Direct at 19-20.

(c) LaPorte County/Hammond's Evidence. Mr. Cearley disagreed with NIPSCO's proposal to implement its proposed Purchased Power Benchmark mechanism. Mr. Shambo in rebuttal stated that Mr. Cearley's position is a situation whereby NIPSCO is unreasonably penalized for adhering to economic dispatch, which is within the control of the Midwest ISO. Mr. Shambo asserted that Mr. Cearley ignored Commission precedent and treatment of purchased power costs for other electric utilities.

(d) IG's Evidence. Mr. Dauphinais recommended NIPSCO's proposed RA Tracker should either be rejected or substantially modified. Mr. Dauphinais opined that in general, rate tracking mechanisms should be avoided except when the magnitude, volatility and unpredictability of the costs and revenues in question could threaten the financial integrity of the utility. Dauphinais Direct at 8. Mr. Dauphinais also suggested that certain Midwest ISO charges should be allocated on the basis of demand rather than energy. Dauphinais Direct at 9.

(e) NIPSCO's Rebuttal Evidence. Mr. Shambo testified that a common theme among the OUCC and Intervenors is a concern that NIPSCO has requested pre-approval or pre-determination of prudence for recovery of certain costs through NIPSCO's tracker proposals. He noted that Mr. Satchwell suggested this notion in regard to the RA Tracker. Mr. Shambo explained that NIPSCO was not proposing pre-approval of specific charges but simply proposing that the Commission approve the tracking mechanism in NIPSCO's requested form to permit the appropriate "vehicles" for future consideration of such cost items to avoid any unnecessary litigation and administrative efforts in the future because the appropriate recovery mechanism is already in existence. Mr. Shambo also testified that NIPSCO agreed to Mr. Eckert's suggested modifications to the Purchased Power Benchmark mechanism, i.e., making it consistent with that approved in Cause No. 43414. In response to Mr. Eckert's recommendation that NIPSCO include the recovery of purchased power costs that are subject to the Purchased Power Benchmark mechanism in its FAC, Mr. Shambo restated NIPSCO's position that purchased power costs are more appropriately handled through the RA Tracker is unchanged.

Mr. Shambo stated that NIPSCO was willing to incorporate the OUCC's suggested changes, with slight modification, in regard to the following items: (i) inclusion of asset/non-asset energy in FAC; (ii) inclusion of ancillary service market energy-related charges as defined by the Commission in Cause No. 43426; and (iii) if and to the extent Midwest ISO develops new charge types or modifies its charge types, NIPSCO would seek authorization from the Commission to include them in the RA Tracker.

Mr. Shambo stated that, in terms of other items proposed by Mr. Satchwell and Mr. Eckert, NIPSCO opposed the suggestion of introducing an RTO Tracker and a Resource Adequacy Tracker. He asserted that NIPSCO's proposed RA Tracker is sufficient to address the various items proposed for inclusion, and NIPSCO is willing to supply the necessary information to the OUCC and Intervenors supporting future recovery under these proposed trackers.

On rebuttal, Mr. Crum testified that the costs and revenues proposed in the RA Tracker involve large, volatile and unpredictable costs and revenues that warrant a rate tracking mechanism. He stated the Midwest ISO charge types proposed to be recovered in the RA Tracker have varied in magnitude over time and many of the charge types have been resettled several times. He also noted that the Commission has approved similar tracking mechanisms for the same Midwest ISO charge types for Vectren South and Duke. In addition, I&M recently received authority to recover similar PJM RTO costs through a functionally equivalent tracking mechanism. Mr. Crum also disagreed with IG's proposed change to the allocation of certain Midwest ISO charge types proposed in the RA Tracker to be on a demand basis. He stated IG did not provide any justification for its proposed allocation. He explained that these costs are allocated by the Midwest ISO to market participants, such as NIPSCO, on an energy basis with the exception of Schedule 26 charges and revenues. He stated that NIPSCO, likewise, has proposed to allocate these Midwest ISO charge types, with the exception of Schedule 26, to its customers on an energy basis.

(f) Discussion and Findings. We find the best practice would be for the Midwest ISO non-fuel costs and revenues and the OSS sharing to be included in one tracking mechanism designated as the RTO Tracker. We further agree with the OUCC that purchased power costs and fuel-related Midwest ISO charge types shall be tracked in the FAC. Therefore, we find that the OUCC's proposal to track Midwest ISO-related costs and revenues and OSS margins through its RTO Tracker and to track purchased power costs and fuel-related Midwest ISO charge types in the FAC is reasonable.

We further find that the OUCC's proposal for a purchase capacity tracker, referred to as the Resource Adequacy Tracker, is approved. This tracker shall be a semi-annual tracking mechanism, coordinated with the FAC audit process. Later in this Order we discuss NIPSCO's proposal to include a credit of $40.5 million, which is projected to be credited to their interruptible customers, in its cost of service study. To the extent that NIPSCO does not have 500 MWs of interruptible load, and therefore has less than $40.5 million of credits to its interruptible customers, this difference should be used to offset any capacity costs recoverable through the Resource Adequacy Tracker. In this way, NIPSCO's customers are protected from paying rates designed to recover higher credits, while at the same time NIPSCO is protected from having reasonably incurred costs not being recovered through its rates and charges.

Finally, NIPSCO's proposed purchased power benchmark, as modified by the OUCC is consistent with the benchmarks we have approved for IPL and Vectren South, and the Commission finds that its use in the FAC tracker is appropriate. The parties should note that pursuant to the Commission's Interim Order in Cause No. 43706 FAC 80 S2, the Commission is conducting a review of the FAC process generally based on two recent refunds of $40.5 million to ratepayers in order to determine whether further modifications of the FAC process would be appropriate.

(3) Modifications to ECRM and EERM.

(a) NIPSCO's Evidence. NIPSCO proposed to clarify that compliance costs for current and anticipated air regulations are eligible for recovery on a semi-annual basis through its ECRM and EERM. Mr. Pack explained that NIPSCO sought to recover emission allowance purchase costs and credit revenues from the sales of emissions allowances to customers. Pack Direct at 11. Mr. Shambo explained that the proposal was designed to promote symmetry such that costs and gains associated with emissions allowances were shared equally with NIPSCO customers. Shambo Direct at 8. Ms. Miller and Mr. Pack further explained that NIPSCO seeks approval to file the EERM on a semi-annual, as opposed to annual, basis. Miller Direct at 49.

(b) OUCC's Evidence. OUCC Witness Pruett did not object to NIPSCO's proposal to file its EERM on a semi-annual, rather than an annual, basis. Pruett Direct at 11. However, Ms. Pruett objected to NIPSCO's proposal to track emission allowance purchase costs and revenues through the EERM. While Ms. Pruett agreed that NIPSCO faces current and future air regulations that may impact the need for allowances, she believed NIPSCO failed to demonstrate two of the three conditions to track emissions allowance costs were satisfied. Pruett Direct at 6. First, she testified that NIPSCO's admission that it did not forecast the purchase or sale of SO2 or NOx emissions allowances in the near future indicated the anticipated costs involved were small. Pruett Direct at 7. Second, she believed that emissions allowance expenses are within a utility's control because it can choose the most cost-effective path to comply with environmental cap and trade regulations. Pruett Direct at 6-7. She claimed a utility would need to show either that it must rely on the emission allowance market for compliance or that such reliance is the least cost environmental compliance strategy before being authorized to track emissions allowance purchase costs. Ms. Pruett was also concerned that NIPSCO had mismanaged its emissions allowances by selling allowances that otherwise could have been used as a low-cost option for future regulatory compliance. Pruett Direct at 9. She asserted allowing NIPSCO to track emissions allowance expenses could give NIPSCO even less incentive to manage allowances in a cost-effective manner.

(c) IG's Evidence. IG Witness Dauphinais opposed NIPSCO's proposal to modify its EERM to the extent that modification allowed NIPSCO to recover emissions allowance costs for substances not currently authorized by Indiana's statutes. Dauphinais Direct at 20. Mr. Dauphinais believed NIPSCO should wait until carbon or other regulations are enacted and then make proposals to recover allowance costs associated with those new regulations. Dauphinais Direct at 20-21.

(d) NIPSCO's Rebuttal Evidence. Mr. Pack continued to believe in the appropriateness of tracking emissions allowance costs and revenues through the EERM. He noted that NIPSCO's proposal is not a break from traditional regulatory practice in Indiana because most of the other investor owned electric utilities are authorized to track emission allowance costs. Pack Rebuttal at 2-3. Mr. Pack testified that the Commission's prior authorization for other electric utilities to track emissions allowance costs demonstrates tracking such costs is consistent with Commission requirements. Pack Rebuttal at 3.

Disagreeing with Ms. Pruett, Mr. Pack concluded that emissions allowance costs satisfied the criteria for tracking. He testified that while NIPSCO currently does not have an estimate of its future costs for emissions allowances, the general consensus in the industry is that the potential cost is significant. He explained that the reason NIPSCO currently has no estimates is due to the uncertainty over legal challenges to current regulations and the form future regulation will take. Pack Rebuttal at 3-4. Mr. Pack also disagreed with Ms. Pruett's belief that emissions allowance costs are within the control of the utility. While Ms. Pruett focused on the utility's freedom to select control technology to mitigate its need for emissions allowances, Mr. Pack believed a more appropriate focus was on the actual costs for necessary emissions allowances, which are set by the market and not within the control of the utility. Pack Rebuttal at 4. He also noted that there was no assurance control technology would be available before potential CO_2 caps are placed into effect.

Mr. Pack also took issue with Ms. Pruett's assertion that NIPSCO's failure to manage its emissions allowances could result in greater future costs for NIPSCO electric customers. He explained that the Clean Air Act Title IV emissions allowances ("Allowances") NIPSCO had previously sold would not likely be available for future compliance based upon the CAIR remand to the Environmental Protection Agency ("EPA"). The remand decision questioned the EPA's authority to utilize historic allowances for future compliance requirements. Based on the Court decision, Mr. Pack believed it is improbable that the allowances will be available for use in future compliance requirements to defer investment in emissions compliance equipment. Pack Rebuttal at 5. Mr. Pack noted NIPSCO's management efforts will include providing information about its plans to manage emissions allowances in its EERM including: (1) regulatory updates on the CAIR remand and CO_2 as they evolve; (2) least-cost compliance options including use of technology and purchase/sale of allowances; and (3) progress of approved projects and purchases/sales allowances.

Mr. Pack also disagreed with Mr. Dauphinais' proposal to declare that the EERM could not include emissions allowance costs to comply with future air emissions regulations. He noted that NIPSCO proposes to use the allowance tracker when needed to result in the most cost-effective path to comply with State/Federal environmental regulations in effect at the time cost recovery is sought. NIPSCO will justify the sale/purchase of any allowances in the EERM filings. The amounts would not be recovered until the Commission (and other parties) has had an opportunity to review the costs and compliance proposals and until the Commission approves recovery of these costs. Pack Rebuttal at 5-6.

(e) Discussion and Findings. NIPSCO has made two proposals relating to its EERM in this proceeding. First, NIPSCO has proposed to file its EERM on a semi-annual basis. While no party opposed this proposal and a semi-annual filing would be consistent with the frequency with which other electric utilities file similar tracking mechanisms, the Commission is concerned with the amount of time and resources tracker review entails in order to have a meaningful review and audit by consumer parties and the Commission. Accordingly, we find that NIPSCO shall file its EERM on an annual basis.

NIPSCO's second proposal is to clarify that its EERM can track emissions allowance costs and revenues. We begin by noting that the environmental tracking mechanisms approved for several other electric utilities in Indiana authorize the recovery of emissions allowance costs and a mechanism for sharing revenues from sales. *See e.g., Ind. Mich. Power Co.*, Cause No. 43306, at 29-30 and 53 (approving a settlement under which utility will implement an environmental tracking mechanism allowing tracking of net emissions costs); *PSI Energy, Inc.*, Cause No. 42359, at 118 (approving a tracking mechanism to recover expenses to purchase NO_x emissions allowance credits and return net proceeds associated with any sales of jurisdictional NO_x sales).

We also find that, with respect to NIPSCO, Mr. Pack has demonstrated that the conditions to track allowance costs have been satisfied. The costs associated with emissions allowances can be substantial. Ms. Pruett's contrary conclusion was based on NIPSCO's indication it did not forecast the purchase or sale of SO_2 or NO_x allowances, but Mr. Pack explained that NIPSCO's inability to quantify that cost resulted from the uncertainty surrounding the regulation of air emissions. This does not mean the cost of acquiring any necessary allowances once the regulatory uncertainty is resolved will not be substantial. Mr. Pack notes that few in the industry dispute that future air emissions regulations, including potential CO_2 regulations, could pose a significant costs for electric utilities. While Ms. Pruett is correct that a utility may have some control over the degree to which it relies on emissions allowance costs, this does not mean that the utility has control over the price it must pay for the emissions allowances. Emission allowances pricing is set by the market, not by the utility. Electric utilities have long been authorized to track fuel costs even though they have some control over the type of fuel that powers its generation equipment. No party disputes that these prices are volatile and this conclusion is bolstered by Mr. Pack's testimony of the significant increase in SO_2 emissions allowances during portions of 2005. For the foregoing reasons, we find that NIPSCO shall be authorized to seek recovery of prudently incurred emissions allowance costs and to credit customers emissions allowances revenues through its EERM. We note that this finding shall not be construed as pre-approving recovery of any such costs, and such specific costs shall be reviewed in the context of its EERM filings.

We also reject Mr. Dauphinais' proposal to limit the recovery of emissions allowances only to air emissions currently eligible for recovery under Indiana statutes. We have already authorized a utility to recover allowances for a pollutant that was expected to be regulated in the future. *See S. Ind. Gas & Elec. Co.*, Cause No. 43111, at 21 (Aug. 15, 2007) (approving the tracking of costs to comply with mercury control regulations when they become effective). While we clarify that NIPSCO should not seek recovery of allowance costs associated with pollutants that are not subject to Federal or State regulation at the time they are purchased, there is no need to require NIPSCO to seek future modification of the EERM to allow recovery of the cost to comply with the regulation of pollutants that become subject to regulation in the future.

The Commission notes that in Attachment CMP-5 to Ms. Pruett's testimony, NIPSCO responded to OUCC Data Request 29-18 and stated its EERM will include 7 months (Jan-Apr & Oct-Dec) of expenses due to annual operation of its U8, 12, and 14 SCRs, and that all other EERM expenses proposed for inclusion in base rates will no longer be tracked in the EERM. However, since the SCR projects are being placed into rate base, all O&M costs for QPCP projects that have been placed into base rates should no longer be tracked. To the extent NIPSCO incurs an increase in O&M expense for those units placed in rate base, those increases may be appropriate for recovery in NIPSCO's next rate case.

Ms. Pruett also recommended that NIPSCO file its progress report on the status of qualified pollution control projects tracked in the Environmental Cost Recovery Mechanism ("ECRM") as part of its ECRM filing. NIPSCO accepted this recommendation and we find NIPSCO should submit this progress report as part of its environmental cost recovery filing.

B. Tariff Rate Class Proposals.

(1) Evidence. Mr. Shambo testified NIPSCO had three overall policy objectives in the development of the rates proposed in this proceeding: (1) the charge for any service rendered is reasonable and just; (2) to the extent possible, the rates should be easy to understand and administer; and (3) the final rates need to consider broader public policy objectives.

With regard to the first objective, he stated that there are two underlying goals: (1) an appropriate balance between the desire of customers for reasonable rates and NIPSCO's responsibility to its shareholders to design rates that give the Company an opportunity to earn a reasonable return on its investment, which ultimately is also in the customer's best interest; and (2) a reasonable level of equity between customer classes in the final rate design. Mr. Shambo stated obtaining a fair return for investors, in turn, requires that rates be designed based on an appropriate revenue requirement level and that the rate structure provide NIPSCO with a reasonable opportunity to recover that revenue requirement. He explained that NIPSCO's industrial customers represent an unusually high percentage of annual load when compared to other utilities, accounting for more than 50% of annual energy usage on NIPSCO's system. He asserted that NIPSCO's proposed cost allocation and rate design takes into consideration the characteristics of all customer classes.

Mr. Shambo stated that NIPSCO is also addressing in its proposed rate design the difference between "peak" and "off-peak" usage. He explained that the advent of the Midwest ISO marketplace has provided much clearer signals on the relative value of electricity for all hours. He asserted that NIPSCO's rate design policy should provide more encouragement for customers to move from peak hours to off-peak hours. He explained that this is a benefit to all customers in three ways: (1) NIPSCO can reduce production from less efficient units; (2) NIPSCO can reduce purchases from the market that by design reflect the dispatch of higher cost units across the Midwest ISO's footprint as demand rises; and/or (3) NIPSCO can make OSS into the Midwest ISO marketplace at the Locational Marginal Prices ("LMP") (with the vast majority of these OSS margins proposed to be passed back to customers through the RA mechanism).

Mr. Shambo testified that NIPSCO does not anticipate that the expiring special contracts will be replaced by new special contracts. He stated that NIPSCO's cost allocation and rate design in this proceeding are more reflective of the actual cost to serve these customers. This better alignment of rates should eliminate the need for special contract rates for these customers.

Mr. Shambo testified that all customers want safe and reliable service priced at rates that are easy to understand. To promote rates that are easy to understand and administer, NIPSCO proposed to reduce the number of rate schedules in its proposed tariff. Mr. Shambo stated that NIPSCO is proposing to reduce the number of customer Rates from 42 to 13. Determining the appropriate number of customer rates is a balance between seeking equitable cost allocation among customers with different characteristics and the simplicity and administrative feasibility of fewer rate offerings with some embedded riders. He stated that NIPSCO has decided to move in the direction of simplicity and administrative feasibility in this proceeding, and testified that, while many of NIPSCO's customers have diverse usage characteristics, NIPSCO's proposed rate restructuring is now able to better align customer load profile with the Company's underlying cost structure.

Mr. Shambo identified key rate development decisions made by NIPSCO and their relation to the Company's objectives including: (1) production costs are allocated based upon 4 Coincident Peaks ("4 CP"); (2) fuel costs are removed from base rates to permit recovery of all fuel costs in the FAC; (3) declining block rates are eliminated; (4) certain billing determinants for demand charges have been developed to recognize the difference between peak and off-peak; (5) rates are constructed that encourage lowering peak demand (Rates 526 and 527); (6) the use of Interval Demand Recording ("IDR") meters will be increased for customers served under Rates 523 and 533; (7) interruptible service is continued and expanded; (8) the total number of rate schedules is reduced and the service offerings are simplified so that customers and stakeholders will better understand the options available; (9) the customer charges were increased to better reflect the cost to serve; (10) a new structure was developed for the Economic Development Rider; and (11) NIPSCO's rate design was adjusted to provide a measured progress toward full cost based rates for certain customer classes in order to avoid rate shock.

Mr. Shambo also explained that NIPSCO eliminated declining block rates because this rate structure encourages customers to increase energy usage. He stated that given current policies in favor of promoting energy efficiency, NIPSCO proposed to eliminate declining block rates.

Mr. Shambo described the reclassification process used in defining the tariff categories. He stated that there are a number of schedules in the commercial/small industrial classes that will be collapsed into just three rate schedules (Rates 521, 523 and 533). He explained that Rate 521 is designed for small commercial customers that do not have demand meters. He testified that these customers are not likely to have as much energy acquisition sophistication as larger customers. He stated that the rate structure is similar to the residential rates with a customer charge and a volumetric per kWh charge.

Curt A. Westerhausen, Manager of Rates and Contracts for NIPSCO, described NIPSCO's proposed Tariff, including the Schedules of Rates, Riders and General Rules and Regulations ("Rules") and explained how the proposed Tariff differs from NIPSCO's current Tariff. Mr. Westerhausen testified NIPSCO's current electric Tariff was developed from NIPSCO's last base rate case dating back to the mid-1980s. In the ensuing years, a number of additional tariff changes, as well as adjustments and updates to existing Rates have been made. In addition, NIPSCO entered into contracts with certain individual customers. He noted that NIPSCO's residential basic rates have remained constant for more than twenty years.

Mr. Westerhausen testified the development of a new electric rate structure will provide customers with a simplified structured approach. This approach was used in all phases of the ratemaking process in order to reflect current conditions and with an eye toward future changes. Mr. Westerhausen summarized NIPSCO's proposed electric Rates and Riders. Mr. Westerhausen sponsored Petitioner's Exhibit CAW-3 that summarized the charges, terms, and applicable Riders for each Rate. He also sponsored Petitioner's Exhibit CAW-2 (Revised), which provided specific details, terms and conditions, rules, etc., applicable to each Rate.

Various witnesses stated concerns regarding the timing and impact of NIPSCO's rate increase, including a discussion of the state of the steel industry and how NIPSCO has communicated its proposals in this proceeding to its customers. For example, Beta Steel offered the testimony of Jeffry Pollock, an energy advisor. Mr. Pollock's testimony focused on issues specific to Beta Steel, including the impact of NIPSCO's proposed rates on Beta Steel, the current state of the steel industry, and specific class cost of service study and rate design issues. Pollock Direct at 5. Mr. Pollock stated that, with the expiration of Beta Steel's special contract, NIPSCO's proposed rates would increase Beta Steel's electricity costs by $9.3 million per year. Mr. Pollock testified that, in light of the current economic conditions facing Beta Steel and other similar companies, NIPSCO's proposed rate increase could create enormous disruption on its large industrial customers. Pollock Direct at 15-16.

David R. Christian, President and Chief Executive Officer of AMPCOR II, d/b/a American Metal Products, Inc., testified regarding the challenges facing smaller manufacturing firms and the potential impact from any increase in electric rates. Mr. Christian stated his belief that NIPSCO's current electric rates have depressed local economic activity and have dissuaded new, energy-intensive companies from locating to LaPorte County. Mr. Christian testified that the LaPorte Manufacturer's Association and the Greater LaPorte Chamber of Commerce are both opposed to NIPSCO's proposed rate increase. Mr. Christian concluded that having access to reliable, affordable electricity is critical for many businesses. Christian Direct at 2-3.

In rebuttal, Mr. Shambo noted that as a result of the passage of time since its last rate case, NIPSCO's presentation included a comprehensive proposal reflecting its proposed revenue requirement and the need to make fundamental changes to its rate design. Mr. Shambo stated the Company proposed steps to improve the offerings available in its tariff and to adjust its offerings to the dynamics of the current wholesale marketplace. He testified it was important to recognize the interrelated nature of NIPSCO's proposed cost allocation and rate design. He emphasized NIPSCO's rate structure is not a series of independently interchangeable parts. Shambo Rebuttal at 2-3.

Mr. Shambo asserted that NIPSCO's opportunity to earn a fair return will be materially affected by the outcome of rate design in this case. He stated there are a significant number of exogenous factors that will have a detrimental impact on NIPSCO if not correctly addressed in the rate design portion of this proceeding. These include, but are not limited to, the ongoing recession, the increased interest and emphasis on energy efficiency programs, and the impact that climate change legislation could have on the rate design and service structure. Shambo Rebuttal at 5.

Mr. Shambo stated that NIPSCO recognizes that there is virtually no good time for a rate increase from the customer's point of view. This concern is magnified by the current recession, regardless if the customer is residential, commercial or industrial. However, the timing of this rate case was mandated by a Settlement Agreement in Cause No. 42824, which was executed by the OUCC and certain customers contained within IG. Mr. Shambo explained that NIPSCO had no alternative but to file this rate case by the date required. Shambo Rebuttal at 6, 40-41.

(a) Rate 511 – Rate for Electric Service, Residential ("RS"). Mr. Westerhausen explained that NIPSCO has three residential Rates in the 800 Series and has created one residential Rate in the 500 Series available to residential and farm customers. Residential electric heating, including electric heat pumps, will be covered by Rider 575 "Electric Spaceheating Rider to Residential Service." Mr. Shambo stated that most residential customers will map easily from Rate 811 to the new Rate 511 schedules. He explained that NIPSCO is converting two additional residential rates into riders for Rate 511. Mr. Shambo explained Rider 575, which is applicable to residential space heating customers. He explained that NIPSCO's current tariff includes three separate space heating rates. Consistent with NIPSCO's effort to simplify its tariff, the three existing rate schedules have been transitioned to one rider, Rider 575. He testified that Rider 575, Electric Spaceheating Rider to Residential Service ("ES") increases the threshold for the discount applicable to the Energy Charge for residential space heating customers to 700 kWh during October through April based upon a review of space heating customer usage. Mr. Westerhausen explained that ES is applicable to Residential Customers that currently have permanently installed electric space heating or electric heat pumps.

Mr. Shambo explained that upon completion of the class embedded cost study, it was apparent that a substantial cost shift was occurring among the three major customer classes. Because existing rates date back to the early 1980s, Mr. Shambo noted that there are many possible explanations for the changes, including fundamental shifts in demand in the commercial class that has moved from smaller units to big box operations during this period, and changing residential usage patterns with the major changes in electrical appliances over this period. Mr. Shambo explained that NIPSCO sought to move toward rates that rely on cost-based allocations with limited inter-class rate subsidies. He explained, however, that moving to cost-based allocations in one step (after 20 years) would result in a 31.4% increase in basic rates for residential customers. He stated that NIPSCO is therefore proposing that only one-third of the full cost-based rate increase to the residential Rate be implemented in this proceeding, yielding an average 16.73% increase in basic rates to residential customers. Shambo Direct at 22.

Mr. Swan asserted that any increase in the customer charge in Rate 511 should be limited to 20% on the basis of rate continuity concerns. He suggested that, if no jurisdictional increase or a reduction is ordered, no change should be made.

NIPSCO disagreed with Mr. Swan's suggestion that NIPSCO should implement a moderation plan regarding its proposed increase to the customer charge. Mr. Shambo stated there does not need to be any moderation of the customer charge as suggested by Mr. Swan. He noted that Mr. Swan did not provide any evidence supporting his suggestion other than the fact that the claimed increase in one aspect of the rate schedule is too much, which misapplies the moderation plan. Mr. Shambo concluded that NIPSCO's proposed customer charge of $10.50 per month is reasonable and fair given the high customer-related fixed costs for this class.

(b) Rates 521 and 523 – Rates for Electric Service, General Service ("GS") Small (521) and Medium (523). Mr. Westerhausen described NIPSCO's General Service rates: Rate 521 – GS Small ("GSS"), and Rate 523 – GS Medium ("GSM"). He stated that GSS is an energy only rate and is available to customers with a rolling twelve month average energy consumption less than 5,000 kWh per month. He explained that GSM is a demand and energy metered rate and is available to customers with demand greater than 10 kilowatts ("kW") but less than 300 kW. NIPSCO Witness Dehring described the Company's efforts to ensure that all GSM customers will have appropriately installed demand meters. Mr. Westerhausen testified that a transitional energy only rate will be used to bill these customers during the interim period.

Mr. Swan asserted that any increase in the customer charge in Rate 521 should be limited to 20% on the basis of rate continuity concerns. He suggested that if no jurisdictional increase or a reduction is ordered, no change should be made.

On rebuttal, Mr. Shambo stated there does not need to be any moderation of the customer charge as suggested by Mr. Swan. He noted that Mr. Swan did not provide any evidence supporting his suggestion other than the fact that the claimed increase in one aspect of the rate schedule is too much, which misapplies the moderation plan. Mr. Shambo stated that NIPSCO's fixed cost incurrence greatly exceeds the revenue that will be generated by the proposed fixed charges. Thus, under Mr. Swan's proposal, NIPSCO would be placed in a position of even greater risk of recovery of its incurred costs. To illustrate this point, Mr. Shambo noted that Mr. Swan is proposing the lowest fixed to variable cost percentage regarding production O&M (*i.e.*, 35% fixed and 65% variable). Mr. Shambo explained that NIPSCO's proposed $10.50 customer charge (in the context of an average monthly bill of $72.13 excluding fuel and trackers) would provide fixed cost recovery much lower than any party's quantification of NIPSCO's fixed production O&M expenses. Therefore, Mr. Shambo concluded, the appropriate application of the moderation plan is to the class as a whole, not to specific charges within the rate class. Shambo Rebuttal at 32-33.

Mr. Shambo testified that proposed Rate 523 contains a broad grouping of customers, estimated at 11,500, that receive power from the distribution system. He explained that this is the first rate schedule that provides a demand charge, and customers were mapped into this rate schedule from Rates 821, 823 and 824 based upon a combination of the assets used to serve these customers, demand data from those customers with permanent demand meters and sampling demand meters. He stated that this is a difficult grouping because of the variety of loads within this class. In recognition of this difficulty, he stated that NIPSCO is planning to expand the use of IDR meters within this group. He also explained that NIPSCO is also providing a number of riders that can be used to better fit customer needs in this Rate.

(c) Rate 526 -- Rate for Electric Service, Off-peak Service ("OPS"). Mr. Shambo explained the nature of Rate 526 and NIPSCO's proposed rate design. He stated that Rate 526 is specifically identified as off-peak Service and was proposed to encourage off-peak usage. He stated that this Rate encourages off-peak service by setting Billing Demand equal to either 100% of On-Peak hours for the past 12 months or 50% of off-peak hours for the past 24 months. On-Peak hours for Rate 526 are defined as 11 AM to 7 PM from April 1 through September 30 and 1 PM to 9 PM from October 1 to March 31, excluding weekends and holidays. Customers with high load during On-Peak hours would pay more on this Rate than under Rate 533 because under Rate 533 only 90% of Peak is used to determine Billing Demand, rather than 100%. By contrast, a Customer whose demand could be migrated to off-peak hours would be encouraged to do so because their Billing Demand would be set at 50%, as compared to 80% under Rate 533. Mr. Westerhausen explained that customers that have demands greater than 300 kW can benefit by shifting their demand from on-peak to off-peak periods by utilizing NIPSCO's proposed OPS. The customer's billing demands are based on the greater of 100% on-peak demand within the last 12 months up, to and including the current month or 50% off-peak demand within the last 24 months, up to and including the current month. A three-year contract is required for service under OPS.

Mr. Phillips noted that NIPSCO proposed to change the definition of billing demand to raise the amount of off-peak demand that counts toward monthly billing demand from 30% to 50%. Mr. Phillips asserted that changing the demand ratchet from 30% to 50% of on-peak load would incent increasing load during on-peak. He noted that NIPSCO changed its billing determinants to coincide with its proposed change in the definition of billing demand under the assumption that "customers will conform usage to rate." Phillips Direct at 22. He asserted that an increase in billing demand units should result in a decrease in the demand charge. Mr. Phillips additionally noted that NIPSCO also proposed to ratchet billing demands to include demands created during the previous 24 months. He asserted that proposed Rate 526 included an increase in the number of on-peak hours from the number NIPSCO has been applying under Rate 825, the requirement of a three-year contract, a new customer charge, and an elimination of the flexibility to deal with unusual circumstances. Mr. Dauphinais also expressed concern that NIPSCO's contracts would be imposed without Commission review or approval. Dauphinais Direct at 28-29.

John Hiler, President of Accurate Castings, Inc., testified about the impact of NIPSCO's proposed Rate 526 on his company. Mr. Hiler described the communications between his company and NIPSCO regarding NIPSCO's proposed rates, and stated his concern that NIPSCO's proposed tariff changes would have a substantial financial and operational impact on his company. Mr. Hiler expressed his concerns regarding NIPSCO's proposed billing demand calculation under Rate 526, the proposed ratchet and the proposed demand change in the number of peak hours.

Mr. Hiler testified that the proposed terms of Rate 526 would have significant financial and operational impacts on his company. Mr. Hiler also expressed his disagreement with NIPSCO's proposed three-year contract term, and stated his belief that NIPSCO should not be permitted to impose any conditions in a new contract that exceed those in the current one-year contract between NIPSCO and his company. Mr. Hiler testified that the proposed Rate 526 would not encourage metal melters to move to off-peak hours and may increase on-peak demand. Mr. Hiler explained that customers currently receiving service under Rate 825 may seek to increase their on-peak load to utilize new demand they would be obligated to purchase under Rate 526, and that Rate 526 ultimately punishes those Rate 825 customers who have modified their operations by moving load to off-peak hours to respond to that rate's price signals. Mr. Hiler then offered some possible ideas to encourage additional load to move from peak to off-peak. Mr. Hiler concluded by recommending that: (a) the monthly billing demand be revised to reflect the criteria in Rate 825; (b) any new contract for existing customers be for a one-year duration, and have the current termination provisions; (c) the peak hours be retained at five as they have been for many years; (d) the customer charge be reduced; (e) language added to provide NIPSCO with the ability to make available additional off-peak hours of service; and (f) the 12/24 month demand ratchet be eliminated, especially retroactively.

Gary R. Connor, Manager of Facility Engineering at Weil-McLain, testified regarding the impact of NIPSCO's proposed Rate 526 on Weil-McLain. Mr. Connor testified that he reviewed Mr. Hiler's testimony and agreed with his objections to the proposed rate increase and rate design of Rate 526. Mr. Connor recommended that the Commission adopt Mr. Hiler's recommendations.

In response to Mr. Hiler's concerns relating to NIPSCO's proposed Rate 526, Mr. Shambo stated that NIPSCO understood his concern with the calculation of a monthly billing demand. Mr. Shambo testified that NIPSCO was willing to define the monthly billing demand using 30% of off-peak demand; however, NIPSCO's allocation of costs to this rate class did not change. Therefore, a shift in the calculation of the billing demand changes the rate determinants, and in the case of reducing it to 30%, the effect is to increase the proposed demand charge to this rate class. Mr. Greneman provided additional detail regarding the effect of reverting to the 30% billing demand determination, and the changes were also reflected in the revised charges contained within Rate 526 as supported by Mr. Westerhausen's rebuttal testimony.

Responding to Mr. Hiler's proposal regarding a 25% level of off-peak demand for purposes of determining billing demand, Mr. Shambo stated NIPSCO had not examined its effect, but it would simply increase the proposed rate to the rate class because it would further reduce the level of billing determinants.

As to Mr. Hiler's statements regarding the Company's proposed monthly customer charge for Rate 526, Mr. Shambo stated NIPSCO's proposed fixed cost recovery is lower than its fixed cost incurrence. He stated that NIPSCO's proposed customer charges are not unreasonable in light of its actual cost structure.

Mr. Shambo also testified that Mr. Hiler's proposal to reduce the number of hours that are considered on-peak under Rate 526 is not appropriate. Lastly, Mr. Shambo addressed Mr. Hiler's concern with NIPSCO's proposal regarding the flexibility of determining on-peak hours; Mr. Shambo stated NIPSCO is maintaining its proposal.

(d) Rate 527 - Rate for Electric Service, Limited Production Large ("LPL"). Mr. Shambo testified that like Rate 526, Rate 527 was proposed to encourage off-peak usage and offered lower costs to any customer willing to limit operation during peak hours to two out of five business days. Mr. Shambo stated that this provision would encourage customers to move demand to off-peak periods, which in turn benefits all customers by more efficiently using NIPSCO's system and reducing the need for additional capacity. NIPSCO expected that some customers would be at the beginning of the week (Monday and Tuesday) and others at the end of the week (Thursday and Friday), further diversifying NIPSCO's demand requirements. NIPSCO included specific provisions for situations when these customers need additional power during periods outside of the hours provided in the Rate.

Mr. Westerhausen stated that proposed rate LPL would be available to customers that have the ability to creatively manage their production in both an on- and off-peak and days-of-the-week fashion. This Rate is available to customers with demands greater than 20,000 kW and the flexibility to utilize the system predominately in the off-peak. He explained that the energy used during non-production hours must be less than 2.5% of the energy used during production hours. If a customer defaults on this condition, the customer will be moved to an appropriate rate. A three-year contract is required for service under LPL.

Mr. Pollock discussed Beta Steel's objection to Rate 527, which Mr. Pollock stated would limit Beta Steel's operating flexibility and would impose burdensome restrictions on Beta Steel's ability to meet its designed production level. Pollock Direct at 17. Mr. Pollock proposed that Beta Steel be moved to the Rate 534 class, and explained how Beta Steel's load could be incorporated into a "combined" Rate 527/534 customer class. *Id.* at 24-26. Mr. Pollock further proposed that the Commission apply the principle of gradualism to this combined class and set rates that will reflect only the actual cost to provide service to these customers. *Id.* at 30. Mr. Pollock also recommended that the Commission adopt the recommendations of IG Witnesses Dauphinais and Phillips. *Id.* at 6.

Mr. Phillips recommended combining Rates 527 and 534 because the one customer mapped to Rate 527 could not operate under the constraints of Rate 527. Phillips Direct at 18.

In response to concerns with NIPSCO's proposed Rate 527, Mr. Shambo stated that, in its rebuttal filing, NIPSCO eliminated Rate 527 from its proposal and reclassified Beta Steel to Rate 534.

(e) Rates 533 and 534 Rate for Electric Service, General Service Large ("GSL") and Rate for Electric Service, Industrial Service Large ("ISL"). Mr. Shambo testified that proposed Rate 533 contains a smaller group of customers, estimated at 900 plus, that take service at the distribution and transmission levels. These customers, by and large, have had demand meters for some time. He stated that customers were mapped into this rate schedule from 817, 820, 821, 823, 824, 826, 832 and 833 based upon a combination of the assets used to serve these customers and demand data from the existing demand meters. He stated that NIPSCO will be replacing existing Demand Indicating meters with IDR meters, in this group for better understanding of load characteristics.

Mr. Shambo explained NIPSCO's rationale for the billing determinants for demand charges used in Rates 533 and 534. He stated that in light of public policy objectives and the goal of providing more cost-reflective price signals within classes, NIPSCO is seeking to create greater awareness of seasonal peak versus off-peak usage in the rates proposed in this proceeding. NIPSCO is proposing that the billing determinants for Rates 533 and 534 be set at the higher of 90% of peak usage, defined as the eight-hour period from 11 AM to 7 PM, Monday through Friday, excluding holidays, during the four summer months of June through September, or 80% of all other hours. The billing determinants for a given month will be the highest of the previous 24 months using the rule described above. NIPSCO chose a 90% threshold, instead of 100%, to avoid overly penalizing a customer that may have had just a handful of high hours during that period. Using 80% of the off-peak period clearly encourages customers to move higher demand into off-peak hours. This billing determinant approach is also consistent with the use of 4 CP for allocating production costs.

Mr. Westerhausen explained that GSL is for customers with demands between 300 kW and 10,000 kW. All customers taking service under GSL would be required to have IDR meters. This is a seasonal rate where all hours outside of the four summer months (June through September) are considered off-peak for demand billing purposes. A customer's monthly billing demand will be based on the higher of 90% of the highest demand during the summer on-peak period within the last 24 months up to and including the current month or 80% of the highest demand at any other time within the last 24 months up to and including the current month.

Mr. Westerhausen explained that ISL is for customers with demands greater than 10,000 kW. This is also a seasonal rate where all hours outside of the four summer months (June through September) are considered off-peak for demand billing purposes. A three-year contract is required for service under ISL. He stated that a customer's monthly billing demand would be based on the higher of 90% of the highest demand during the summer on-peak period within the last 24 months up to and including the current month or 80% of the highest demand at any other time within the last 24 months up to and including the current month or 80% of the contract demand.

Mr. Phillips noted that NIPSCO's proposed demands of 90% of Maximum Summer Peak Hour Demand, 80% of the Maximum Non-Summer Peak Hour Demand, or 80% of Contract Demand are an increase from current Rate 833. Phillips Direct at 25-26. He stated that the requirement of a three-year contract to receive firm service pursuant to a tariff is unreasonable. *Id.* at 28.

In response to Mr. Phillips' concern regarding NIPSCO's proposed three year contracting requirement in its industrial tariffs, Mr. Shambo articulated NIPSCO's need to require a new three-year contract to promote stability and support the Company's planning efforts. Mr. Westerhausen testified that NIPSCO is not seeking discretionary authority to redefine the terms and conditions under which it will provide service through a variety of new customer contract requirements. The standard contract template was admitted into evidence as Petitioner's Exhibit CAW-R3.

(f) Demand Ratchet/Billing Determinants. The tariffs sponsored by Mr. Westerhausen in NIPSCO's direct case included a 24-month demand ratchet for customers on Rates 526, 533 and 534.

Mr. Pollock made some recommendations regarding NIPSCO's proposed change from an 11-month to a 24-month billing demand ratchet. Mr. Pollock testified that a 24-month would be a dramatic change that is not consistent with the practices of other Indiana electric utilities. Pollock Direct at 36-37. Mr. Pollock recommended that the Commission approve a 12-month demand ratchet. *Id.* at 37.

Messrs. Phillips and Hiler proposed that NIPSCO should not be allowed to use a 24-month ratchet provision for development of rate determinants. Mr. Hiler testified that under Rate 825, the monthly demand is the greater of the maximum on-peak half-hour demand, 30% of maximum off-peak half-hour demand, 75% of highest billing demand for the prior 11 months, or

500 kW. He explained that his company operated its facilities so as to keep its on-peak usage at 30% of peak usage, which is the price signal sent by Rate 825. Hiler Direct at 6. He testified that his company had made investments to keep on-peak within 30% of off-peak. *Id.* at 7.

Mr. Phillips opined that use of 24-month look back for the demand ratchet penalizes those with higher billing demand for responding to previous rate. Phillips Direct at 24. He recommended that the new demand ratchet start at zero.

In rebuttal, Mr. Greneman explained that NIPSCO must establish rate determinants to calculate rates. To the extent that rate determinants, for a given rate, are higher than billing determinants for that rate, NIPSCO will under collect its revenue requirement allocated to that rate. He stated that the 24-month ratchet provision is NIPSCO's method for defining billing demand that is appropriate for reasons of equity, an opportunity to earn its authorized return, revenue stability and supporting NIPSCO's long-term capital investment decisions and associated financing. NIPSCO's proposal defines the demand billing determinant for each Rate 533 and 534 customer based upon the greater of 90% of their summer on-peak demand or 80% of any other hour over the preceding 24 months. He testified that NIPSCO's proposed rate determinants were developed under the same rules using 2007 test year data, noting that there is consistency between NIPSCO's proposed rate determinants and billing determinants that will be applied to those rates.

NIPSCO Witness James A. Heidell addressed in rebuttal NIPSCO's need for an appropriate method for recovering demand costs allocated to the industrial customers in light of the significant drop in industrial customer loads compared to the 2007 test-year levels. Mr. Heidell testified that the Company's average monthly peak loads of industrial customers for the third quarter of 2008 were approximately 22% below those in the test year. Heidell Rebuttal at 1-2.

Mr. Heidell explained that NIPSCO's proposed 24-month demand ratchet is an appropriate method to use for Rates 526, 533 and 534 given NIPSCO's unique conditions and the decrease in peak demand since the test year. He stated that NIPSCO has significant fixed costs associated with generation, transmission and sub-transmission plant installed to serve its industrial customers and its industrial load is a much larger share of total load than most utilities. Mr. Heidell testified that NIPSCO's industrial load is over 50% of its total sales volume, and therefore a large share of the Company's total costs are allocated to industrial classes in the ratemaking process. He explained that this unusually high percentage of industrial load creates particular risk to the Company to the extent its cost recovery is dependent on industrial customers' electricity demand in each discrete billing month with no ratchet adjustment. Mr. Heidell explained that NIPSCO stands to significantly under-collect the rate of return the Commission finds reasonable in this case unless industrial customer demands are reflective of the computation of the rate determinants used to compute the demand charges. Heidell Rebuttal at 5.

Mr. Heidell stated that NIPSCO's proposal for a 24-month backward looking ratchet for defining billing demand is a reasonable approach for dealing with the high reliance on demand charges to recover fixed costs. Mr. Heidell testified under NIPSCO's proposal, billing demand for Rate 526, 533 and 534 customers would be defined as their highest monthly demand in the past 24 months. He explained that use of a 24-month period to determine billing demands would help preserve NIPSCO's ability to recover the fixed costs incurred to meet industrial load. Heidell Rebuttal at 6.

Mr. Heidell testified that two primary rate design principles that support NIPSCO's proposal to implement a 24-month historical ratchet are (1) equity and (2) that rates should be designed to provide a reasonable opportunity to earn the allowed rate of return. He stated that along with these two primary principles, rate design involves balancing multiple additional objectives including economic efficiency, understandability, and administrative feasibility. Heidell Rebuttal at 6.

Mr. Heidell explained that it is equitable to apply a 24-month ratchet to customers on Rates 526, 533 and 534 because the Company has invested in generation, transmission, and sub-transmission to serve these customers. These costs are fixed in the short- and medium-terms. He stated the proposed ratchet is similar to the concept of a facilities charge, in which customers pay on a fixed monthly basis (rather than on the basis of usage in a particular month) for facilities installed to accommodate their demand. Mr. Heidell explained that basing a portion of large customers' bills on their demands over the past 24 months compensates the Company fairly for the investment made to ensure adequate resources to meet their load requirements. Heidell Rebuttal at 6.

He explained this approach is also fair to other customer classes, which might, under other cost allocation procedures, have to absorb costs not recovered from the industrial customers. Mr. Heidell testified that, in order for the industrial customers to pay their fair share of the system costs, a ratchet (or a facilities charge or some other fixed demand charge approach) is not just appropriate but in this case essential, given the difference between the test-year demands and the anticipated rate-year customer demands. Heidell Rebuttal at 7.

Mr. Heidell testified that, while the use of 24-month ratchets may not be commonplace, whether it is an appropriate method should be considered in light of a particular utility's specific circumstances. He explained that unless taken into account in the rate-setting process, this decrease will impair the Company's ability to earn a fair rate of return on facilities that were largely built to serve the loads of the industrial customers. He stated that although the 24-month ratchet may not be sufficient to allow NIPSCO to indefinitely earn its full allowed rate of return, due to the rolling 24-month calculation of customer billing demands, this method will limit the revenue shortfall compared to a 12-month ratchet or, as the industrial customers propose, a ratchet starting at zero. Heidell Rebuttal at 7.

Mr. Heidell testified that should the Commission reject the 24-month ratchet and accept IG's proposal for rate structures with no ratchets, then the use of annualized fourth quarter 2008 peak demands to compute the demand charges for Rates 526, 533 and 534 is an appropriate approach that will largely offset the otherwise highly negative impact on NIPSCO's ability to recover its allowed rate of return. Mr. Heidell stated that, if the Commission were to adopt IG's proposal that the new demand ratchet start at zero, NIPSCO's revenues would fluctuate much more than those of other electric utilities that have demand ratchets. He explained that the average of NIPSCO industrial customers' peak demands in the last three months of 2008 was approximately 22% below these customer's average monthly peak demands in the test year and that NIPSCO does not expect industrial activity in NIPSCO's service territory to recover to pre-recession levels for some time. Mr. Heidell testified that NIPSCO will have little possibility of earning the rate of return that the Commission finds reasonable in this case unless the reduction in industrial loads is taken into account either in the definition of billing demand incorporated in the tariff structure, or in the rate determinants used to calculate the demand charges. Heidell Rebuttal at 5.

(g) Rate 536 – Rate for Electric Service, Interruptible Industrial Service ("IIS")/Rider 581. Mr. Shambo described proposed Rate 536 for interruptible service and the Company's rationale for its design and the expected volumes used to create the rate schedule. He stated that interruptible load that conforms to the Midwest ISO interruption requirements would benefit all customers by allowing NIPSCO to avoid building new facilities or paying for capacity to meet reliability standards. He asserted that NIPSCO's proposed Rate 536 conformed to the Midwest ISO interruption requirements. He explained that NIPSCO allocated only 50% of the capacity costs to this rate schedule because of its ability to interrupt service on short notice.

He stated that NIPSCO evaluated the load characteristics of the customers eligible for this tariff to determine the billing determinants used in the proposed rates. This determination was based on those customers that (a) currently are on interruptible service or (b) have self-generation options.

Mr. Shambo explained that the counterpart to Rate 536 in NIPSCO's current rates and charges (Rate 836) limits the rate's availability to 110 MW. NIPSCO estimated that the total load of current customers who would benefit from this Rate at 250 MW.

Mr. Westerhausen explained that IIS is for Customers who have the ability to interrupt and/or curtail electric demand with 10 minute notice. Interruptions would be requested on an economic basis while curtailment would be requested in regard to bulk electric system reliability. He stated that a customer may continue to receive service upon being interrupted, but will be billed at the Midwest ISO LMP at the NIPSCO load node. A three-year contract is required for service under IIS. A customer's monthly billing demand will be based on the contract demand.

Mr. Dauphinais asserted that certain elements of NIPSCO's proposed Rate 536 were unreasonable including the "transmission" customer requirement; the 250 MW cap on customer participation; the 10 minute notice requirement; the curtailment and interruption limitations; the mandatory participation in the economic interruption provisions of Rate 536; the "buy through" rate for economic interruptions; and the additional $2,200 per month customer charge. Mr. Dauphinais also suggested that NIPSCO clarify that 'first through the meter' means that a customer can only be required to interrupt down to their firm Rate 533 or 534 demand. (Page 50.) Mr. Phillips recommended a 75% credit rather than 50% credit in billing demand charges for Rate 536 customers. He asserted that NIPSCO will interrupt load more frequently in the future than in the past based on economic considerations. He noted that a 75% credit was accepted in NIPSCO's last base rate case.

In response to Messrs. Phillips' and Dauphinais' concerns with and changes to NIPSCO's proposed Rate 536, Mr. Shambo explained that NIPSCO's proposed structure for Rate 536 was based upon the proposed allocation of costs while also taking into consideration other factors such as the proposed moderation plan and the OSS margin proposal. Mr. Shambo testified that NIPSCO agreed that Mr. Dauphinais' demand credit of $6.75/kW-month is a reasonable amount of credit based upon the avoided amortized cost of a combustion turbine, and has determined that the applicable credit to the rate class is $40,500,000. He stated that, to the extent the parties desire changes to the rate structure, it was necessary to re-calculate the rates based upon those changes to assure that the allocation of costs remains consistent among customers within the rate class and in comparison to other classes and that NIPSCO retains the opportunity to achieve its revenue requirement.

Mr. Shambo testified that NIPSCO was also willing to incorporate IG's proposal to increase the MW limit under Rate 536 and to permit 34 kV primary customers to participate under that rate schedule and to eliminate the customer charge. Because of these changes, however, NIPSCO proposed that Rate 536 become Rider 581 to Rates 533 and 534. Mr. Shambo asserted that this change would simplify the understanding of the interruptible tariff option in concert with the applicable underlying rate schedules. Therefore, NIPSCO re-calculated the effect of some of the changes proposed by IG.

Mr. Shambo stated that NIPSCO was not willing to remove the ability to economically interrupt customers under Rider 581. He noted that Mr. Dauphinais seems to promote a situation whereby Rider 581 customers are paying at interruptible rates for firm service. He explained that these interruptible customers will be provided an opportunity to receive power at coal-based, variable prices for much of the time with a credit to their demand charge. He stated that a fundamental tenet of NIPSCO's proposed interruptible rider is the ability to interrupt customers when market pricing signals dictate a situation that benefits non-interruptible customers. He asserted that economic interruptions will benefit the vast majority of customers who do not subscribe to the interruptible rider. Because the amount of the credits to interruptible customers is shifted to NIPSCO's non-interruptible customers in the cost of service study and included in their rates, it is only reasonable that those other customers receive the opportunity (and benefit from it) through NIPSCO's interruption of Rider 581 customers when it can otherwise save costs. It is NIPSCO's intent to preserve the opportunity to economically interrupt customers under Rider 581 when the wholesale market pricing supports such interruption, including situations of facilitating OSS or purchases for non-interruptible customers. This is the benefit of the bargain for non-interruptible customers paying for the credit under Rider 581. Thus, Mr. Shambo asserted NIPSCO must retain the ability to economically interrupt Rider 581 customers.

(h) Rate 541 – Rate for Electric Service, Water Pumping ("WP"). Mr. Westerhausen explained that WP is available on a metered basis to Municipalities, the Indiana Department of Natural Resources, Corporations or Persons operating under an exclusive franchise in furnishing water service at retail, and on an unmetered basis to applicable residential and small commercial customers pumping sewage water and waste. Energy consumption on the non-metered pumps was estimated for the purposes of allocating applicable Riders.

(i) Rate 544 – Rate for Electric Service, Railroad Power Service ("RR"). Mr. Westerhausen stated that RR is available only to existing railroads or to a non-profit commuter transportation district operating said railroads. Electricity will be supplied for the operation of trains on a continuous electrified right-of-way of the customer.

(j) Rate 550 – Rate for Electric Service, Street Lighting ("SL"). Mr. Westerhausen explained that SL is available for street, highway and billboard lighting service. Twenty separate lighting rates from the 800 Series are combined into SL. Billing is based upon type, ownership and responsible maintaining party of the lighting fixture. New to SL is the applicability of various Riders to pre-allocated amounts of electric usage based on specific light fixture sizes and types. He also stated that Rate SL eliminates the geographic-specific billing metric.

(k) Rate 555 – Rate for Electric Service, Traffic and Directive Lighting ("TDL"). Mr. Westerhausen stated that TDL will be closely related to existing Rate 895, Traffic and Directive Lighting of the 800 Series and is applicable to traffic, directive, and similar lighting.

(l) Rate 560 – Rate for Electric Service, Dusk to Dawn Area Lighting ("DDAL"). Mr. Westerhausen testified that DDAL is similar to SL. Customers taking service under DDAL would be billed based on estimated energy usage by type of fixture. Also, DDAL will be subject to the same various Riders as SL. He stated that a one-year contract is required for service under DDAL.

(m) Rider 574 – Adjustment of Charges for Power Factor ("PF"). Mr. Westerhausen stated that the PF Rider is applicable to on-peak demands in the proposed electric Rates and incents the customer's efficient use of service. The 800 Series rates had four separate metrics for determining power factor charges. The proposed 500 Series Rider standardizes these different calculations into a single method. Mr. Greneman also discussed the new power factor adjustment calculation.

Mr. Pollock recommended that the proposed Power Factor charge be based on the embedded costs of capacitors, not current costs. Pollock Direct at 39. Mr. Pollock also proposed to lower the reference level to 85% lagging. Mr. Pollock concluded that while some increase in the power factor charge is justified, the Commission should set the Power Factor charge to reflect NIPSCO's actual embedded costs. Pollock Direct at 8, 39.

In rebuttal, Mr. Greneman stated that with regard to the level of the power factor, NIPSCO proposed that customers be charged for power factor correction below a reference level of 95% lagging, which is consistent with the reference power factor in present Rate 845. Mr. Greneman explained that, if NIPSCO were to lower the reference level to 85% lagging (the level recommended by Mr. Pollock), the result would be to penalize those customers that have already made the needed efforts to correct their power factor to above 85%. He noted that NIPSCO based the charge on its current cost to add capacitor banks, arguing that pricing should be based on embedded costs, as current costs are at odds with cost of service, which uses embedded cost principles. Mr. Greneman testified that NIPSCO has not used current costs for capacitors in the cost of service study, rather only in the design of the power factor rates. He described the purpose of the power factor charge, which is to provide an incentive to customers to correct their power factor. He explained that current costs provide the appropriate economic signal to customers to decide whether to continue to run their equipment at a lower power factor or to invest in equipment to raise their power factor and lower their overall costs.

(n) Rider 575 – Electric Spaceheating Rider to Residential Service ("ES"). Mr. Westerhausen explained that ES is applicable to Residential Customers that currently have permanently installed electric space heating or electric heat pumps. Rider ES offers a reduced charge for monthly energy consumption over 700 kWh during the months from October through April.

(o) Rider 576 – Thermal Storage Rider ("TS"). Rider TS is applicable to current customers with thermal storage equipment capable of meeting 40% of the total btu requirements for their air-conditioned space during the on-peak daily demand. The discount has been modified from a discount of off-peak energy and demand to a straight 5% discount of the non-fuel portion of the customer's thermal storage bill.

(p) Rider 577 – Purchases From Cogeneration and Small Power Production Facilities. Mr. Westerhausen testified that Rider 577 is available to a Qualifying Facility, as defined in the Rules. A contract is required between the Company and each Qualifying Facility, setting forth all terms and conditions governing the purchase electric power. Availability of back-up and maintenance power is also addressed in Rider 577.

(q) Rider 578 – Interconnection Standards. Mr. Westerhausen explained that Rider 578 is provided in accordance with the applicable standards, rules and regulations of the Commission's Rules as specified in the Indiana Administrative Code.

(r) Rider 579 -- Net Metering. Mr. Westerhausen stated that Similar to Rider 578, Rider 579 is provided in accordance with the applicable standards, rules and regulations of the Commission's Rules as specified in the Indiana Administrative Code.

(s) Rider 580 – Economic Development Rider ("EDR"). Mr. Westerhausen testified that the EDR is available to non-residential Customers upon demonstrating the fulfillment of certain new production, increased load and other economic-related characteristics that would otherwise have not occurred absent the availability of this EDR. Mr. Shambo stated that it is in the best interest of NIPSCO and its customers that NIPSCO promote its service territory as a viable location for new businesses. He explained that benefits to NIPSCO customers include an increased tax base from the investment and potential new employment with related income tax, sales tax and property tax benefits.

Mr. Westerhausen testified NIPSCO is proposing discounts to non-fuel rates to avoid shifting the burden to other customers. NIPSCO will also assure that the rate will be above the incremental cost to provide service to a new customer. NIPSCO sought the ability to discount the non-fuel rate for up to five years and by up to 50% in the first year declining to 10% by year five. NIPSCO will evaluate a number of key variables prior to offering the discount, including whether the facility is located in a "brownfield" area. Mr. Shambo explained that NIPSCO has a number of areas where existing transmission and distribution facilities are not at capacity and locating new facilities in those areas can be done at the lowest incremental cost.

(t) Rider 582 (Off-Summer Peaking Rider for Proposed Rates 523 and 533). On rebuttal, Mr. Greneman explained that, at the field hearing held in this Cause, it was brought to the Company's attention that its proposed rate structure would: have a detrimental effect on a group of customers that are currently on energy-only Rate 821; are sufficiently large in terms of annual kWh as to be mapped to proposed Rates 523 and 533; but with the inclusion of the demand charge on these rates, would experience an inordinate increase as compared to their bills under present Rate 821. These customers share in common diminished summer use as compared with non-summer use. There are approximately 550 such customers compared with 12,504 customers on proposed Rates 523 and 533 combined. Mr. Greneman stated that to acknowledge these customers usage patterns, the Company is proposing to provide a 50% credit to the generation portion of the demand charge in both rates for the 550 customers.

In doing so, the class revenue requirement would remain the same, but the revenue shortfall would be compensated by increasing the generation portion of the demand charge for the remaining customers in each rate. Mr. Greneman explained that to be eligible for Rider 582, customers must take service under proposed Rate 523 or 533 and have 12 months of billing activity. Customers must also have an average daily usage for the four summer months (June to September) that is less than 75% of their average daily usage for the eight non-summer months. Customers taking service under Interruptible Industrial Rider 581 are not also eligible for this rider.

(2) Discussion and Findings. The Commission notes at the outset that no party proposed maintaining the current 800 Series rates, terms and conditions. Therefore, our findings will relate to NIPSCO's proposed 500 Series rates, terms and conditions. Several 500 Series rate classes and riders were not opposed by any Party, including Rates 523, 541, 544, 550, 555, 560 and Riders 575, 576, 577, 578, 579, 580, and 582. Based upon the evidence of record, the uncontested proposal for these Rate Classes and Riders is approved as proposed by NIPSCO. With regard to the other rate classes and Riders, we will address each issue individually.

Rate 511. Aside from the moderation plan, which was addressed above, the only contested issue regarding Rate 511 was the level of the customer charge. As noted by Mr. Shambo, NIPSCO presented sufficient evidence to support the charge, and Mr. Swan even agreed with that assessment. His only opposition was premised on the concept of moderation. Regarding that issue, the Commission agrees with Mr. Shambo that the goal of rate design should be to assure adherence to cost-causation principles. Mr. Swan did not contest that the residential class customer charge was not cost based, but rather that anything above a 20% increase was too high. He also acknowledged on cross-examination that if the residential class did not pay this cost, then some other class would be required to pay more than their fully allocated costs. Tr. at DD-32. Based upon the evidence of record, the Commission finds that Rate 511 as proposed by NIPSCO, including the customer charge, shall be approved.

Rate 521. The only contested issue regarding Rate 521 was the level of the customer charge. As noted by Mr. Shambo, NIPSCO's customer charge does not approach recovery of its fixed costs. Any change in the customer charge would not change the costs assigned to Rate 521, but only their allocation. Based upon the evidence of record as discussed above, the Commission finds that Rate 521 as proposed by NIPSCO, including the customer charge should be approved.

Industrial Rates 526, 533 and 534. Various parties raised concerns relating to NIPSCO's proposed Industrial Rates 526, 533 and 534. The first concern was use of 50% vs. 30% off-peak billing demand for Rate 526. We agree with Messrs. Hiler and Phillips that changing the current billing demand ratchet of 30% off-peak to a 50% off-peak demand ratchet would incent increased on-peak usage. Such a result is not what NIPSCO has testified they intended, and on rebuttal they agreed to modify their tariff accordingly (including incorporating the effect into its cost of service study results). Mr. Hiler proposed a 25% level of off-peak demand for purposes of determining billing demand for Rate 526, but Mr. Shambo stated NIPSCO had not examined its effect. As noted by Mr. Shambo, such a modification would simply increase the proposed rate to the rate class because it would further reduce the level of billing determinants. Based upon the concerns, and the willingness of NIPSCO to revise its filing, we find that NIPSCO's billing demand ratchet for Rate 526 should be set at 30%. We approve this modification while recognizing that a shift in the calculation of the billing demand changes the rate determinants and, in the case of reducing it to 30%, the effect will be to increase the proposed demand charge to this rate class.

As to Mr. Hiler's statements regarding the Company's proposed monthly customer charge for Rate 526, NIPSCO's cost of service study illustrates that its proposed fixed cost recovery is lower than its fixed cost incurrence. Therefore, we find that NIPSCO's proposed customer charges are reasonable in light of its actual cost structure.

While the Commission understands Mr. Hiler's proposal to reduce the number of hours that are considered on-peak and his proposal to give NIPSCO flexibility to determine on-peak hours, given the evidence that NIPSCO presented, we find that Mr. Hiler's proposals are not appropriate.

As to Messrs. Hiler's and Phillips' concern regarding the requirement that customers in Rates 526 and 534 execute three year contracts, the Commission understands the need of an energy utility to plan for its projected load and to have a reasonable opportunity to earn its authorized return. Such planning is made easier and more accurate when required pursuant to a contract. We find that the contract contained in Petitioner's Exhibit CAW-R3 is sufficient in detail to serve the needs of NIPSCO, while at the same time addressing the concerns of the various industrial witnesses concerning a requirement of a contract for a customer receiving service pursuant to a tariff.

With regard to the demand ratchet, the evidence is uncontested that NIPSCO's industrial load is over 50% of its total sales volume, and therefore a large share of the Company's total costs are allocated to industrial classes in the ratemaking process. Mr. Heidell explained why NIPSCO's proposed 24-month demand ratchet is an appropriate method to use for Rates 526, 533 and 534 given the unique conditions of NIPSCO. NIPSCO has significant fixed costs associated with generation, transmission and sub-transmission plant installed to serve its industrial customers, but its industrial load is a larger share of total load than most utilities. It is further not the Commission's intent to place NIPSCO in a position that its new rates and charges will be established upon conditions that are not fully representative of current volumes. NIPSCO presented evidence regarding its 4th quarter of 2008 level of volumes, which is appropriately considered in this proceeding because it falls within twelve months of its 2007 test year. On the other hand several witness testified that a 24-month ratchet provision was excessive and beyond the standard length of such ratchet provisions. After considering all of these factors, we direct the Company to revise the ratchet provision to 12 months.

Finally, we must note that despite NIPSCO's assertion to the contrary, it is not evident that NIPSCO endeavored to develop tariff provisions that responded to the requirements of its large industrial customers, to the extent reasonably possible. We were troubled by Ms. Odom's statement on the first day of the evidentiary hearing that the rate case filing represented the opening round of negotiations between NIPSCO and its industrial customers concerning its new tariff rates. To the Commission, such remarks indicate callous indifference to concerns of a majority of its load and demonstrate a poor management decision. In the absence of special contracts, we would encourage NIPSCO to continue discussions with its industrial customers to develop tariffs that are more narrowly tailored to its industrial customers' needs while furthering NIPSCO interests, resulting in a win-win scenario for both sides.

Rate 527. Rate 527 was proposed to encourage off-peak usage and offered lower costs to any customer willing to limit operation during peak hours to two out of five business days. Mr. Phillips and Mr. Pollock testified that no party would take service under the proposed rate. Given this testimony, NIPSCO made a determination to withdraw Rate 527 from its tariff proposal. The Commission, therefore, will not consider any modifications to Rate 527, but rather will consider any relevant issue in its consideration of Rate 536 and Rider 581.

Rate 536/Rider 581. Various parties assailed the following elements of NIPSCO's proposed Rate 536: (1) the "transmission" customer requirement; (2) the 250 MW cap on customer participation; (3) the 10 minute notice requirement; (4) the curtailment and interruption limitations; (5) the mandatory participation in the economic interruption provisions of Rate 536; (6) the "buy through" rate for economic interruptions; (7) the additional \$2,200 per month customer charge; and (8) the 50% credit in billing demand charges vs. the 75% credit that was approved in NIPSCO's last base rate case. In response, NIPSCO agreed that customers served by a 34.5 kV distribution line would be considered sub-transmission customers and eligible for various rates and riders. NIPSCO also agreed to increase the cap on interruptible participation to 500 MW. NIPSCO agreed to modify the ten-minute notice requirement to four hours. NIPSCO Witness Westerhausen explained that many of the revisions in NIPSCO's proposed Rules were designed to address "NIPSCO becoming a member of, and maintaining operation compliance with, the Midwest ISO." Westerhausen Rebuttal at 17. In rebuttal NIPSCO proposed elimination of Rate 536 and implementation of Rider 581. Given that the interruptible provisions of the tariff are now in a rider, there is no additional customer charge associated with it. In rebuttal NIPSCO also agreed that Mr. Dauphinais' demand credit of \$6.75/kW-month is a reasonable amount of credit based upon the avoided amortized cost of a combustion turbine. Thus, the remaining contested issues are: (1) the mandatory participation in the economic interruption provision; and (2) the "buy through" rate for economic interruptions.

With regards to the ability to economically interrupt, the Commission agrees with NIPSCO that IG promoted a construct whereby Rider 581 customers are paying at interruptible rates for nearly firm service. These interruptible customers will receive power at coal-based, variable prices for much of the time with a credit to their demand charge. The purpose of an interruptible tariff provision is to give the utility the ability to interrupt customers when market pricing signals dictate a situation that benefits non-interruptible customers. Such economic interruptions will benefit customers who do not subscribe to the interruptible rider because it provides for a reduction to demand that would otherwise be needed; furthermore, it is equitable because NIPSCO's non-interruptible customers are allocated additional costs, and it is only reasonable that those other customers receive the opportunity (and benefit from it) through NIPSCO's economic interruption of Rider 581 customers. The ability to economically interrupt customers under Rider 581 when the wholesale market pricing supports such interruption, including situations of facilitating OSS or reducing purchases for non-interruptible customers, is reasonable. This is the benefit of the bargain for non-interruptible customers subsidizing the credit under Rider 581. Therefore, the Commission finds that these provisions of Rider 581 are reasonable and shall be approved.

Rider 574. NIPSCO's proposed PF Rider is applicable to on-peak demands in the proposed electric Rates. Mr. Pollock recommended that the proposed Power Factor charge be based on the embedded costs of capacitors, not current costs and proposed to lower the reference level to 85% lagging. NIPSCO's proposed Rider standardizes the Power Factor calculations currently found in NIPSCO's tariff into a single method and is designed to encourage the customer's efficient use of service.

NIPSCO's proposal that customers be charged for power factor corrections below a reference level of 95% lagging is consistent with the reference power factor in present Rate 845. If NIPSCO were to lower the reference level to 85% lagging, the result would be to penalize those customers who have already made the needed efforts to correct their power factor to above 85%. The purpose of the power factor charge is to provide an incentive to customers to correct their power factor. Use of current costs provides the appropriate economic signal to customers to decide whether to continue to run their equipment at a lower power factor or to invest in equipment to raise their power factor and lower their overall costs. Based upon the evidence presented, the Commission finds that NIPSCO's proposed PF Rider shall be approved as proposed.

13. Demand Response.

A. Evidence. Mr. Dauphinais proposed that NIPSCO be required to institute a demand response tariff. On cross-examination, Mr. Dauphinais admitted that the Midwest ISO business rules concerning demand response had not been finalized. He also admitted that he was unaware of whether any of the members of IG were prepared to offer demand response resources. Tr. at GG-29.

In response to Mr. Dauphinais' testimony, Mr. Shambo noted that the Commission presently has an open investigation into demand response in Cause No. 43566. Mr. Shambo stated that NIPSCO stands ready to develop reasonable rules with its customers to facilitate such offerings, but this is dependent upon the finalization of the rules at the Midwest ISO level. Mr. Shambo stated that because there is an ongoing Commission proceeding and the Midwest ISO rules are not yet finalized regarding demand response, it is inappropriate to propose such tariffs at this time.

B. Discussion and Findings. While the Commission recognizes the desire of the industrial customers to have available demand response tariffs, the Commission notes that on July 28, 2010, the Commission issued its Order in Cause No. 43566 the Commission issued its Order in Cause No. 43566 requiring utilities to develop and file tariffs or riders authorizing the participation of its retail customers in Midwest ISO demand response programs within 90 days from the date of the Order, and the Midwest ISO rules are not yet finalized regarding demand response. Therefore, the Commission finds that it is not appropriate to order such tariffs through this Cause.

14. Rules.

A. Evidence.

(1) Rule 1 – Definitions. Mr. Westerhausen explained that the definition section in Rule 1 is new and is intended to assist customers in fully understanding the terms used in the proposed Rates, Riders and Rules. It also contains the definitions of the new seasonal On-Peak and Off-peak Hours that are utilized in the proposed Rates and Riders.

(2) Rule 2 – Rates, Rules and Regulations. Mr. Westerhausen testified that proposed Rule 2 revises current Rule 1 to clarify that if there are conflicts with the language between Contracts, Rates, Riders and Rules, which will prevail. Mr. Dauphinais stated that Rule 2.2 (as well as Rules 4.1, 4.3, 5.8 and 6.5) would explicitly give priority to contract terms over all the terms that are reviewed and approved by the Commission thereby giving NIPSCO new authority to decide what terms to impose by contract on customers unable to seek service from competing suppliers, and the contract terms imposed by NIPSCO would have priority over the terms set forth in the Commission-approved tariff. Dauphinais Direct as 30-31. In rebuttal, Mr. Westerhausen explained that NIPSCO's Proposed Rule 2 provides a hierarchy of which will prevail when considering Rates, Riders, Rules and Contracts. Mr. Westerhausen testified this prioritization of interpretation order sequence is an important part of the Company's efforts to simplify and clarify its existing rules. Experience working within the terms and conditions of its existing rules has shown that some confusion and conflict has occurred when interpreting and applying the terms and conditions of the tariffs, riders and other service rules and regulations. He asserted that providing an ordered sequence of interpretation to standard contract terms of service–as reviewed by the Commission–will help achieve the twin goals of simplification and clarification of service and operation.

Mr. Westerhausen described the Company's intent of proposed Rule 2.1. He acknowledged that existing tariffs cannot be superseded by any new tariff unless and until the new tariff is properly approved and implemented in accordance with the appropriate Commission rules and regulations governing the implementation of such new tariffs.

He also explained that with its proposed changes to the existing rules, NIPSCO was not seeking discretionary authority to redefine the terms and conditions under which it will provide service through a variety of new customer contract requirements. He stated that NIPSCO has no intention to undermine Commission oversight, facilitate deviations from the Commission-approved provisions of NIPSCO's filed tariffs, provide the potential for discrimination in service, and/or codify activity in any way that could possibly result in the denial of service to customers. Mr. Westerhausen testified NIPSCO's proposed changes will not erode in any way its duty as a public utility to provide reliable service and meet demand within its assigned territory.

Mr. Westerhausen disagreed with Mr. Dauphinais that NIPSCO's contracts will be imposed without Commission review or approval and that NIPSCO will have sweeping authority to establish its "right" to require contracts for service. He stated that NIPSCO takes its obligation to serve very seriously. Mr. Westerhausen stated it is not NIPSCO's intention to have the Commission review each of the individual contracts. Currently the Commission does not approve the individual contracts. He opined that if the Commission approves the standard contract, there is no reason for each of the contracts to be reviewed. He asserted that NIPSCO intends to submit its standard contract template for service for review by the Commission. In this way, complete Commission oversight and review is maintained. The standard contract template was admitted into evidence as Petitioner's Exhibit CAW-R3.

Mr. Westerhausen stated that NIPSCO is proposing to utilize a three year standard form contract for customers taking service under Rates 526, 534, Rider 581 – Interruptible Industrial Service, and any Rate 533 customers that are also taking interruptible service under Rider 581.

Mr. Westerhausen testified the signing of a contract is among the conditions of accepting service under the following current rates: (1) Rate 824 – General Service – Large Use; (2) Rate 825 – Metal Melting Service; (3) Rate 826 – Off Peak Service; (4) Rate 832 – Industrial Power Service; (5) Rate 833 – Industrial Power Service; (6) Rate 836 – Interruptible Industrial Power Service for Air Separation Processes; and (7) Rate 845 – Industrial Firm Incremental Power Service. He stated that inclusion of a signed contract for service requirement in the select 500 series rates is an extension of the requirement of a signed contract under the approved 800 series rates. He stated that the standard contract will define the rate the customer is taking service under, the electric service voltage, the voltage that the customer is being metered, and the contract demand.

(3) Rule 3 – Character of Service. Mr. Westerhausen stated that Rule 3.1 is a new rule to clarify the standard Company installations to provide service. Rule 3.2 revises current Rule 3.7 to reflect the proposed change of defining 34 kV as a primary service voltage pursuant to the FERC Seven-Factor Test.

(4) Rule 4 – Application, Service Request or Contract. Mr. Westerhausen explained that proposed Rule 4 is a combination of current Rules 2, 3 and 21. He stated that there were no significant changes made to these rules. Mr. Dauphinais expressed the same concerns with Rules 4.1 and 4.3 as he expressed with regard to Rule 2.2. Mr. Westerhausen described the Company's intent of proposed Rule 4.3, which is to make its rules simpler and easier to facilitate. He stated that disclosing that any promise, agreement or representation made between NIPSCO and a customer will not be binding unless incorporated into a Commission-approved contract, eliminates any possibility of misunderstanding or confusion associated with a contract. He noted that this rule was designed to protect both the customer and NIPSCO in a way that the responsibilities and expectations of all parties are properly recorded and understood with a clear record signifying such.

(5) Rule 5 – Prediction of Rate Schedule Selection. Mr. Westerhausen described proposed Rule 5 as a combination of current Rules 10, 11 and 12. He stated that there were no significant changes made to these rules.

(6) Rule 6 – Service Extensions and Modification. Mr. Westerhausen stated that proposed Rule 6 is a combination of current Rules 22, 30, 33, 41 and 42. This new rule includes the proposed modifications to NIPSCO's method of determining the amount of contributions and guaranteed minimums required from customers when NIPSCO extends basic service facilities to provide standard electric service. These proposed modifications will also be used to determine the amount of advances required to be paid by builders and developers prior to their sites receiving service. Mr. Dauphinais expressed concerns regarding Rule 6.5, which requires a contract. Dauphinais Direct at 34. In rebuttal, Mr. Westerhausen described in more detail NIPSCO's proposed Rule 6. He stated that the sizing and design of transmission facilities is unique to each customer regarding, among other things, expected loading, wire size, tower and sub-station design, breaker installation and preferred disconnect and lock-out strategy. NIPSCO's proposed Rule 6.2 provides in advance, the opportunity to analyze each request for new, or extension of existing, transmission service. To that end, he testified that proposed Rule 6.2 is another example of NIPSCO's attempt to insure procedures are in place that allow for the optimization of the design and installation of its capital assets in meeting these new transmission load requirements.

(7) Rule 7 – Customer Installation. Mr. Westerhausen testified that proposed Rule 7 is a combination of current Rules 23 and 32 and stated that there were no significant changes to these rules.

(8) Rule 8 – Company Equipment on Customer's Premises. Mr. Westerhausen stated that proposed Rule 8 is a combination of current Rules 4, 5, 17, 24, 28 and 36, and testified that there were no significant changes to these rules.

(9) Rule 9 – Metering. Mr. Westerhausen explained that the proposed Rule 9 is a combination of current Rules 16, 25 and 26. He stated that Rule 9.4 was added for additional clarification.

(10) Rule 10 – Customer Service Deposits. Mr. Westerhausen testified that proposed Rule 10 is a combination of current Rules 9A and 9B and stated that there were no significant changes to these rules. Mr. Dauphinais asserted that proposed rule 10.2 allows for NIPSCO to ask for deposits to Commercial & Industrial customers whenever they want, which is excessive. (Page 39, lines 21-24).

(11) Rule 11 – Rendering and Payments of Bills. Mr. Westerhausen stated that proposed Rule 11 is a combination of current Rules 6A, 6B and 7. He noted that the Senior Citizen Payment Plan was expanded to include the legally disabled and people receiving social security benefits and is now the Social Security Payment Plan. If the customer meets the criteria, their due date could be extended up to ten calendar days.

(12) Rule 12 – Disconnection and Reconnection of Service. Mr. Westerhausen stated that proposed Rule 12 is a combination of current Rules 8, 15 and 19 and there were no significant changes to these rules. Mr. Dauphinais expressed concerns with the disconnection rules, but admitted in cross-examination that they were consistent with the Commission's current rules. Tr. at GG-46.

(13) Rule 13 – Service Interruptions and Curtailments. Mr. Westerhausen testified that proposed Rule 13 is a combination of current Rules 34 and 35, and has been modified to incorporate the changes to NIPSCO's Curtailment and Interruption procedures as a result of being a member of the Midwest ISO. Mr. Dauphinais also raised issues with the limitation of liability provision (Rule 13.1). He stated that the proposed rules alter the extent to which NIPSCO is relieved of liability for service failures. Mr. Dauphinais also noted that interruptions for the purpose of non-emergency repairs used to receive tem days notice, and now that time has been shortened to only 48 hours. Dauphinais Direct at 42.

In rebuttal, Mr. Westerhausen described the Company's proposed Rules as they pertain to NIPSCO's membership in the Midwest ISO. He stated that a number of NIPSCO's proposed Rules have been updated to account for changes in the operation of the bulk electric system and NIPSCO's participation as a member of the Midwest ISO. The proposals in Rule 13 are consistent with the intent of Proposed Rule 6.2, for example, which identifies a contract requirement for new customers taking service at transmission level voltages. This is included to allow NIPSCO to model, and coordinate in advance with the Midwest ISO, any effect these new transmission loads brought on-line by a new customer will have on the safe and reliable operation of the bulk electric system. Mr. Westerhausen explained that knowing these effects in advance will allow NIPSCO to optimize its asset management efforts in meeting these new load requirements in the most reliable, cost effective manner.

(14) Rule 14 – Miscellaneous and Non-reoccurring Charges. Mr. Westerhausen stated that proposed Rule 14 includes (1) reconnection fees and (2) a charge to reimburse the Company for non-sufficient and returned payment fees. Reconnection fees are calculated to cover the cost of reconnection of service and vary depending on when the service is provided (during normal working hours, after normal working hours or holidays), as well as whether the reconnection is done at the meter or at the pole. The distinction between where the reconnection is done is an expansion of the existing rule. The current rule also changes the former non-sufficient funds fees to encompass both paper and electronic payment transactions. He stated that Rule 14 (Miscellaneous and Non-reoccurring Charges) reflects an increase in the charges for reconnection service based on the Company's analysis of actual costs incurred to perform such services.

Mr. Swan suggested that reconnection charge increases should be limited to 20% if the Commission grants a total increase close to what the Company has requested, and if no increase or a significant reduction in jurisdictional revenues is approved, the charges for reconnection at the meter should not change, but modest increases could be applied to reconnections at the pole.

In rebuttal, Mr. Shambo responded to Mr. Swan's concerns with the proposed increases to the reconnection charges. He noted that NIPSCO had presented evidence of the cost-based nature of these services, and noted that Mr. Swan further acknowledged that NIPSCO had provided such evidence. Mr. Shambo reiterated that it is appropriate to moderate these charges and doing so would introduce a cross-subsidy.

B. Discussion and Findings. We would note at the outset that proposed rules 1 3, 7, 9, and 11 were unopposed by the other parties to this proceeding. Based upon the evidence of record, the uncontested rules are approved as proposed by NIPSCO. With regard to the other proposed rules, we will address each issue individually.

(1) Rule 2 – Rates, Rules and Regulations. The Industrial Group raised concerns with the language in 2.1 because it is ambiguous as to whether the language, if approved, would allow a tariff to become effective upon the issuance of a Commission order approving it, but prior to the tariff being filed with the Commission. The Commission recognizes the Industrial Group's concern and agrees that the proposed language is ambiguous. As proposed, the rule reads "the Tariff, or any part thereof, may be revised, amended, or otherwise changed from time to time and any such changes when approved by the IURC, will supersede the present Tariff." This language could be read to make a tariff's change effective upon the approval of the Commission, even if the tariff has not been filed with the Commission, which would violate the filed rate doctrine. The Company's Reply brief noted its concurrence with the OUCC and IG suggested changes. Therefore, we find that proposed Rule 2.1 shall be changed to read "the Tariff, or any such part thereof, may be revised, amended or otherwise changed from time to time and any such change when approved by the IURC and filed with the Commission will supersede the present tariff.

As to proposed Rule 2.2, the Industrial Group raised concerns because, as proposed, the Company "shall have the right to execute contracts for service under any rate schedule or rider." The first provision of proposed rule 2.2 then sets up the interpretation hierarchy such that in the event of a conflict between any provision of a contract, rate schedule, a rider and/or the rules, the contract would take first priority as to interpretation. The Commission agrees that when these two provisions are taken together, the Company would have the authority to require a contract from a customer under any rate tariff and every contract would trump the tariff language. This result would essentially allow NIPSCO to alter the terms and conditions of an approved tariff by requiring a contract that would not be subject to the Commission's review. NIPSCO's witness, Mr. Westerhausen essentially confirmed that during cross-examination. Tr. PP-114 -115. The Company's Reply brief noted its concurrence with the OUCC and IG suggested changes. The Commission finds that Rule 2.2 should be revised to limit the Company's right to execute contracts for service under only those rate schedules or riders that specifically require a contract for service. Once that revision is made, the second sentence of the paragraph need not be changed.

(2) Rule 4 – Application, Service Request or Contract. The Industrial Group raised concerns with several portions of Rule 4 to the extent that it may allow NIPSCO to require a contract for the provision of service even in the absence of a contract requirement in the tariff and to the extent it relieves NIPSCO of its duty to serve its captive customers. This concern is similar to the problem we found in Rule 2.2 and shall be addressed in a consistent manner.

There are essentially two primary types of contracts that a utility may enter into with its customers. The first is one that simply fleshes out customer specific requirements but is governed by an existing tariff. The second type is those contracts that must be approved pursuant to I.C. 8-1-2-24 and 25. The point of demarcation between these two types lies ultimately with the Commission.

In light of these considerations, we find that Rule 4 is unclear and shall be revised consistent with Rule 2.2.

(3) Rule 5 -- Prediction of Rate Schedule Selection. The Industrial Group challenged the language in proposed Rule 5.8 regarding the default provision. Under proposed Rule 5.8, if a large volume industrial consumer has not entered into a contract under proposed Rates 526, 527, 534 and 536, the default tariff would be Rate 533. While this provision alone may not be troublesome, when taken with other proposed provisions that purport to give NIPSCO very broad discretion in what contract terms will be required, this Commission agrees with Mr. Dauphinais' point that Rule 5.8 could provide NIPSCO with additional leverage when dealing with customers who would be eligible for service under Rates 526, 527, 534 and 536/Rider 581. As discussed previously, any contract requirement under a published tariff shall be limited in nature as to what terms are to be included. To the extent that the contents of the required contract are left open ended, proposed Rule 5 would once again blur the line between those contracts that simply enable a customer to become eligible under a specific tariff rate and contracts that fall under Sections 24 and 25 requiring Commission approval. Accordingly, we find that Rule 5.8 shall be revised consistent with Rule 2.2.

(4) Rule 6 – Service Extensions and Modification. The only disputed issue under Rule 6 concerns the contract requirement under Rule 6.5. Given the planning and expense that are involved in service extensions, the Commission is not persuaded that the contract requirement proposed in Rule 6.5 is unreasonable and accordingly, we find that the rule as proposed shall be approved.

(5) Rule 8 – Company Equipment on Customer's Premises. While the OUCC and IG raised concerns in their respective proposed orders suggesting the proposed Rule 8.3 inappropriately shifts the duty to acquire easements from NIPSCO to the customer and that the language in proposed Rule 8.5 is overly broad regarding the phrase "unauthorized use of electricity" when disconnection is at issue (the third sentence of Rule 8.5), the Commission finds no evidence supporting such a suggestion. Accordingly, we find proposed Rule 8 is reasonable and that the rule as proposed shall be approved.

(6) Rule 10 – Customer Service Deposits. In proposed Rule 10.2, NIPSCO would be granted broad discretion in requiring both new and existing large volume customers to provide deposits or letters of credit as security for service without the ability to appeal or rebut a deposit determination. We agree with the Industrial Group that NIPSCO's proposed Rule 10.2 deviates from the foundation established by the Commission's regulations on deposit and would discriminate against large users. To the extent that such regulations (170 IAC 4-1-15) may not apply to non-residential customers, we believe that equity, absent a showing of need to reasonably discriminate, dictates that such company specific rules as proposed herein should be fundamentally the same. In short, non-residential customers are entitled to an equitable and non-discriminatory method of determining credit worthiness and similar earnings on any equivalently held deposit and to the ability to appeal a deposit determination. We find that Rule 10.2 must provide non-discriminatory treatment to its commercial and industrial customers and provide a clearly defined process by which such customers may appeal a deposit determination. Absent such a revision, the Commission rejects Rule 10.2 as proposed.

(7) Rule 12 – Disconnection and Reconnection of Service. We agree with the Industrial Group that Rule 12.3 grants too much discretion to NIPSCO for disconnection. NIPSCO's proposed rules must be reviewed in the context of the whole rules. See Pet. Ex. CAW-R1 at 17. When NIPSCO's proposed rules are taken as a whole, proposed Rule 12.3 provides excessive authority to NIPSCO. Under the rules as a whole, failure to post a deposit would be sufficient reason for disconnection under Rule 12.3, which would provide additional leverage for NIPSCO to require deposits from its large customers. It also would allow disconnection if a customer challenged a contract requirement. This provision, when coupled with NIPSCO's attempt to acquire open ended authority on imposing contract terms would be an impediment to a customer's ability to challenge a contract requirement. In addition, the lack of supply will not always justify disconnection at the customer's peril. This provision when considered in light of NIPSCO's attempt to change its standard of care for liability to gross negligence grants too much power to NIPSCO. Therefore, we reject proposed Rules 12.3 (a), (b) and (d).

The Commission recognizes the concerns expressed by the IG but is not persuaded that the disconnection authority proposed in the remainder of Rule 12.3 coupled with the other rule revisions directed herein is unreasonable and accordingly, we find that the rule as modified shall be approved.

(8) Rule 13 – Service Interruptions and Curtailments. Some of the concerns the Industrial Group raised with Rule 13 have been addressed by NIPSCO's rebuttal testimony wherein NIPSCO acknowledged that it did not intend to use the defined term "Interruption" in Rule 13 but rather the lower case term. Pet. Ex. CAW-R1 at 14.

NIPSCO's rebuttal did not address the Industrial Group's concerns regarding the standard of care for liability from "fault, neglect or culpability," which is currently in Rule 18, to the gross negligent standard proposed by NIPSCO. NIPSCO presented no testimony to justify this changed standard. Consequently, we reject NIPSCO's proposed change and find that NIPSCO shall retain its original "fault, neglect or culpability" language from Rule 18.

NIPSCO also proposed to change the reduction in the length of notice it would provide for service interruptions for non-emergency repairs. NIPSCO's current industrial tariffs provide that industrial customers would have at least ten days notice of any service interruptions for non-emergency repairs. NIPSCO has proposed to shorten the notice to 48 hours for all customers. Although NIPSCO attempted to justify the change in its rebuttal testimony, the Commission finds no valid reason to reduce the notice time from ten days to two days. Consequently, the Commission finds that the notice to all customers for non-emergency interruptions should be ten days.

(9) Rule 14 – Miscellaneous and Non-reoccurring Charges. As we have stated previously the Commission desires for charges for a service to be based on the cost of providing that service to the extent practical. We also recognize the significant charge increases proposed by NIPSCO as discussed by OUCC Witness Swan and are cognizant of particular impact such charges may have on the smallest and poorest customers who can least afford it. However, non-recurring charge types are inherently different from recurring charge types and therefore the foundation for application of the gradualism principal is reduced. Based on the totality of the evidence of record, the Commission approves the Rule 14 charges proposed by the Company.

15. FERC Seven-Factor Test.

A. Evidence. NIPSCO Witness Greneman explained that in Order 888, the FERC asserted jurisdiction over all unbundled transmission and left distribution regulation to the states. The FERC Order issued the Seven-Factor Test guidelines to help utilities and State regulators delineate its transmission and distribution facilities between what is under the FERC jurisdiction and subject to open access rules versus what is under state jurisdiction and not subject to open access. Mr. Greneman stated that each state is authorized to approve proposed separation of transmission and distribution functions using the Seven-Factor Test, with FERC retaining authority to review and make a final determination on treatment of assets. In this proceeding, NIPSCO is seeking approval to revise its segregation between transmission and distribution facilities to be consistent with orders from FERC.

Mr. Greneman stated that NIPSCO formed a working group and retained expert consultants in 2003 to systematically catalog and classify its facilities and to make recommendations with respect to the guidelines. Mr. Greneman testified that the NIPSCO 345 kV and 138 kV systems are the major bulk power carriers for the Company. All 345 kV and 138 kV lines are classified as transmission under the application of the Seven-Factor Test. The 69 kV was classified as transmission. He stated that virtually all of the 69 kV system is networkable and capable of performing a transmission function. The 34 kV lines, which were classified as distribution in the Seven-Factor Test, were the Company's older sub-transmission voltage lines that were originally used where 69 kV was not available. He explained that over the years, sub-transmission voltages such as 34 kV and 25 kV (in other utilities) tended to operate as distribution as is the case with NIPSCO's older 34 kV system. The technical characteristics and function of the 12.5 kV and below type of facility matches the definition of local distribution under the FERC's Seven-Factor Test.

Mr. Greneman explained that at the conclusion of the Seven-Factor Test a set of rules was developed in the form of an algorithm to be used to reclassify existing transmission and distribution assets in accordance with the results of the Seven-Factor Test. This would also be used as the guideline for booking future plant additions to FERC primary accounts. The procedures were set forth in Exhibit No. RDG-2, Schedule 4.0 of Mr. Greneman's testimony.

NIPSCO Witnesses Hershberger and Dehring testified regarding NIPSCO's implementation of the FERC Seven-Factor Test and the resulting classifications of NIPSCO's facilities as transmission or distribution. Mr. Dehring testified that as a result of joining the Midwest ISO, NIPSCO must implement FERC's Seven-Factor Test set forth in FERC Order No. 888. Mr. Dehring explained that the Seven-Factor Test analyzes the electric delivery system under seven different views to determine how the various components of the electric delivery system should be classified between transmission or distribution. Mr. Dehring stated that NIPSCO retained Stone & Webster Consultants, Inc. to assist in performing the Seven-Factor Test, and that based on the results of that analysis NIPSCO made several changes to how its transmission and distribution assets were classified.

More specifically, Mr. Dehring testified that after reviewing the results of the Stone & Webster study, NIPSCO determined that all of NIPSCO's electric delivery system facilities rated 69 kV and above, networked or operated as radial, should be classified as transmission. All of NIPSCO's electric delivery system facilities rated below 69 kV should be classified as distribution. Mr. Dehring stated that this resulted in $108,644,289 of transmission assets being reclassified as distribution assets and $14,599,077 of distribution assets being reclassified as transmission. Dehring Direct at 6.

Although the actual transfers were not made to NIPSCO's plant and reserve accounts until the beginning of 2008, they were incorporated in the cost of service study as a functional reclassification among primary accounts.

NIPSCO Witness Hershberger described other adjustments to NIPSCO's test year utility plant in service resulting from NIPSCO's implementation of the FERC Seven-Factor Test and other account reclassifications. He explained that other equipment transfers were needed to correct the original classification of the equipment, as shown on Petitioner's Exhibit MEH-8.

B. Discussion and Findings. No party contested these classifications or objected to NIPSCO's Seven-Factor Test in this proceeding. As discussed earlier in this Order, parties raised concerns regarding the allocation of costs to customers served by 34.5 kV facilities, but these concerns were addressed by the creation of a sub-transmission category for purposes of the cost of service study. We find that NIPSCO properly implemented the test and has appropriately determined which of its facilities should be classified as transmission facilities and which should be classified as distribution facilities for purposes of the Seven-Factor Test.

16. Ring Fencing.

A. Evidence. LaPorte and Hammond jointly submitted the testimony of Dr. John Wilson, a consulting economist, who testified regarding potential "ring fencing" conditions for NIPSCO that could be implemented by the Commission. Dr. Wilson defined ring fencing as a package of "distancing mechanisms" designed to insulate a utility company's credit risks from the financial and business risks of a parent corporation. Dr. Wilson explained that ring fencing is intended to ensure the financial stability of the regulated utility and the reliability of its service. Wilson Direct at 4.

Dr. Wilson outlined the specific ring fencing provisions that he recommended the Commission adopt for NIPSCO, including: (1) separate books of accounts and accounting systems; (2) separate credit and debt; (3) limitations on NIPSCO's ability to provide dividends to NiSource; (4) certain notice and preapproval requirements; and (5) specific financing guidelines. Wilson Direct at 13-17. Dr. Wilson concluded that these provisions, if adopted by the Commission, would provide a formal structure for ring fencing and would provide NIPSCO's ratepayers with specific regulatory protections. Wilson Direct at 17.

Petitioner submitted rebuttal testimony of David J. Vajda to respond to Dr. Wilson's recommendation that the Commission impose certain ring fencing conditions on NIPSCO in its Order in this proceeding. Mr. Vajda is Vice President, Treasurer and Chief Risk Office of NiSource and Vice President and Treasurer for its subsidiaries, including NIPSCO. Mr. Vajda testified why Dr. Wilson's recommendations are unnecessary and inappropriate and, in some cases, unduly burdensome.

Specifically, Mr. Vajda explained that the Commission already has access to the records of NIPSCO and records of affiliates that have transactions with NIPSCO related to joint or general expenses. Mr. Vajda added that many affiliate agreements between NIPSCO and NiSource companies are required to be filed with the Commission. Based on the foregoing, Mr. Vajda concluded that Dr. Wilson's recommendation (a) that "[t]he Commission or its agents may audit the accounts of NIPSCO, its parent (NiSource) and its affiliates which are the bases for charges to or transfers from NIPSCO," recommendation (b) that "NIPSCO and its parent (NiSource) shall provide the Commission access to all books of account, as well as all documents, data and records of their affiliated interests, which pertain to transactions between NIPSCO and its affiliated interests," and the part of recommendation (c) providing that "[a]ll NIPSCO financial books and records and those of its parent and affiliates shall be completely and immediately accessible in Indiana" are unnecessary.

Mr. Vajda went on to explain that the part of Dr. Wilson's recommendation (c) that provides that "NIPSCO shall maintain its own accounting system, separate from its parent's and its affiliates' accounting systems" reflects Dr. Wilson's misunderstanding of NIPSCO's accounting structure. As Mr. Vajda stated, NIPSCO maintains its Walker General Ledger system to maintain its financial books in accordance with the USOA and this system is already maintained by NIPSCO separate and distinct from the systems used by other NiSource entities. NIPSCO prepares its own financial statements for regulatory filings required by the Commission and FERC. NIPSCO also submits its financial results for each accounting period to NiSource Consolidation Accounting for the purpose of preparing the consolidated financial statements needed for NiSource's filings with the SEC. The consolidated financial statements are also used to allow management reporting in a consistent format throughout NiSource.

Mr. Vajda testified that it would be inappropriate and an unnecessary expense for the Commission to require that NIPSCO maintain separate credit ratings from its parent and affiliates as recommended by Dr. Wilson given the possibility that in the future, NIPSCO may not have debt outstanding to third parties.

With respect to Dr. Wilson's recommendation (e) that: "[e]xcept as may be expressly authorized by the Commission, NIPSCO will not extend credit or make loans to, or pledge its public utility assets as collateral for the benefit of, its parent or any of its affiliates and will not guarantee any debt of its parent or any of its affiliates" and recommendation (l) requiring approval of a "cash management plan incorporating best practices for insulating NIPSCO's credit from the risks associated with participating in a shared money pool with such affiliates," Mr. Vajda responded that NIPSCO already must obtain Commission approval for issuance of long-term debt and pledges of NIPSCO's public utility property, so the recommended conditions are unnecessary in the context of those transactions. To the extent Dr. Wilson's recommended conditions would apply to NIPSCO's participation in the NiSource money pool to invest surplus funds and borrow on a short-term basis, Mr. Vajda stated the recommendations should be rejected as they would have a detrimental effect on the NiSource money pool program which is very beneficial to NIPSCO and its customers. Mr. Vajda described the NiSource money pool in which NIPSCO and its affiliates may invest surplus funds on a daily basis and borrow funds on a short-term basis on terms that are more advantageous than participants in the money pool would be able to obtain on their own.

Mr. Vajda testified that Dr. Wilson's recommended restrictions on dividends and distributions from NIPSCO to its parent or any subsidiaries or affiliates are unnecessary, inappropriate and unduly burdensome. Imposing this requirement on NIPSCO, explained Mr. Vajda, could create a negative impression in the investment community and cause rating agency and investor uncertainty that could have adverse consequences in the current economic market.

Mr. Vajda testified that NIPSCO's most current agreement with NCS is on file with the Commission and affiliate charges are further reviewed and subjected to scrutiny in the context of rate cases. Accordingly, Mr. Vajda stated that Dr. Wilson's recommendation (i) providing that specific Commission authorization be required for expenses allocated or directly charged to NIPSCO by its parent and affiliates is unnecessary, inappropriate and unduly burdensome.

Finally, Mr. Vajda stated that no justification had been shown for requiring specific Commission authorization for certain transfers and other dispositions or NIPSCO's use of debt proceeds as is recommended by Dr. Wilson in recommendations (j) and (k).

NIPSCO also submitted rebuttal testimony of Steven M. Fetter, President of Regulation UnFettered, responding to the "ring fencing" conditions recommended by Dr. Wilson. Prior to founding his energy advisory firm, Mr. Fetter was head of the utility ratings practice at Fitch, Inc. and before that served as Chairman of the Michigan Public Service Commission. Mr. Fetter began by stating that the majority of major ring fencing efforts among U.S. regulators relate to particular unquantifiable risks in the context of acquisitions, mergers and spin-offs involving complex fact patterns. Mr. Fetter therefore disagreed with Dr. Wilson's testimony describing the financial circumstances of NIPSCO within the NiSource holding company structure as a "classic case" for ring fencing. Mr. Fetter said it would be very unusual for a regulatory commission to impose ring fencing conditions on a utility as part of a general rate case such as this proceeding. Mr. Fetter further explained that the concerns related to the mixing of regulated and unregulated activities within the same consolidated parent corporation–which Dr. Wilson cites as the impetus behind what he calls a growing interest in ring fencing for public utilities–are absent in the case of NIPSCO, because almost all of NiSource's subsidiaries are involved in traditionally-regulated utility and interstate pipeline businesses. Fetter Rebuttal at 9.

Mr. Fetter testified that Dr. Wilson's ring fencing recommendations in this proceeding come at a particularly inopportune time, given the current state of the U.S. capital markets. The recent economic turmoil made it difficult for some utilities to easily access the capital markets. According to Mr. Fetter, actions by a regulator creating the perception that the regulator is asserting control over a utility's dividend policy and retained earnings, matters normally within the discretion of management, is not a reasonable strategy in the current economic environment. In Mr. Fetter's rebuttal, he stated his belief that actions that would establish a perception that the regulator is creating barriers to the realization of efficiencies and economies of scale from a utility's participation in a normal holding company structure could cause additional concern and uncertainty for the investment community. Fetter Rebuttal at 13.

Mr. Fetter disagreed with Dr. Wilson that ring fencing should be implemented in order for NIPSCO to receive an improved credit rating. In Mr. Fetter's view, substantially limiting interaction between NiSource and its regulated Indiana subsidiary to possibly improve NIPSCO's credit ratings by a notch would increase investor uncertainty and diminish benefits flowing from shared managerial expertise and economies of scale. Mr. Fetter also pointed out that NiSource's businesses, being almost 100% regulated, are subject to constant scrutiny by regulators with authority to protect consumers and prevent abuses.

Mr. Fetter then offered his views with regard to some of the specific ring fencing conditions proposed by Dr. Wilson. Mr. Fetter cautioned against allowing regulatory access to information to be used so broadly as to allow regulators to prospect through the books and records underlying the proprietary activities of the utility's holding company or other affiliates. Mr. Fetter also warned that, with respect to the proposed conditions related to financial relationships and transactions between NIPSCO and its affiliates, it is important that regulators not create unnecessary barriers to the achievement of efficiencies and economies of scale that can be derived from being part of a holding company structure, including the benefits of NIPSCO being able to finance through its financing affiliate and participate in the NiSource money pool. Mr. Fetter disagreed with Dr. Wilson's proposed conditions that would interfere with or restrict distributions and dividends from NIPSCO to NiSource. He explained that investors rely upon a utility management's expected dividend policy, particularly within the utility sector. Interference with those policies by regulators would cause investor concern and render the maintenance of a certain equity level much more difficult during times of market stress. Finally, based on his experience as head of the utility ratings practice at Fitch, Mr. Fetter strongly disagreed with Dr. Wilson's proposed recommendation (g), which would grant regulators special access to non-public information supplied to credit rating agencies. As Mr. Fetter explains, rating agency personnel are expressly permitted to receive and analyze the most highly confidential and sensitive company information by the SEC's Regulation FD. Dr. Wilson's proposal would lead issuers to be less forthcoming to rating agencies regarding information that might be relevant to a rating agency's determination of the appropriate rating. Mr. Fetter discussed the difficulty of tracking confidential information, citing a recent news report of two SEC staff attorneys who mishandled confidential information made available to the agency during SEC investigations of certain issuers.

B. <u>Discussion and Findings</u>. LaPorte has presented evidence supporting its ring fencing proposal, while the other parties presented evidence that ring fencing was unnecessary. LaPorte describes how ring fencing would serve to protect NIPSCO from the financial and business risks of its parent corporation and affiliates. In contrast, the remaining parties that presented evidence on this issue argued that ring fencing is not necessary, and may actually harm NIPSCO's ratepayers by creating uncertainty among the investment community, ultimately making financing more expensive for NIPSCO and resulting in higher rates for its customers.

In Cause No. 42292, we addressed concerns that AES, Indianapolis Power & Light Co.'s parent corporation, could potentially affect IPL's capital structure and creditworthiness. *Petition of Indianapolis Power & Light*, Cause No. 42292, 2003 Ind. PUC LEXIS 110 (February 12, 2003). The Commission discussed our concerns over the relationship between IPL and AES as follows:

> As a regulatory agency charged with overseeing utilities, the Commission is attuned to factors that affect all utilities in general and individual utilities as well. With regard to IPL and its ultimate parent AES, the Commission is aware of considerable media attention to the recent financial difficulties of AES. To ignore such reports would be a dereliction of our responsibility to exercise our statutory authority in an informed manner. In the case at hand, the OUCC's witness Mr. Robertson testified that IPL's ultimate parent, AES, has experienced significant financial pressure in the market, and that the financial troubles with IPL's parent companies may lead to cash outflows from IPL that might result in insufficient cash to provide reasonably adequate service, or result in an inappropriate debt to equity ratio. IPL's witness Ms. Horwitz testified that "IPL's credit rating was dropped by the Standard & Poor's rating agency solely because of a practice that Standard & Poor's has on linking a subsidiary to a much lower rated parent." She further conceded that implicit in the rating drop is a concern by the investment community that IPL's parent companies might extract cash from IPL in an amount that would leave IPL in a difficult situation. The evidence presented supports a finding, and we find, that the poor financial condition of AES has created a situation that could endanger the financial health of IPL.
>
> At this time, IPL has a reasonable capital structure, and based on a snapshot of IPL's financial condition, the Commission has approved IPL's financing request. However, faced with an ultimate parent, AES, that is in financial distress, there is a risk that IPL may need to surrender dividends in such an amount that a factor critical to the Commission's approval of a financing request -- the utility's capital structure -- could be substantially changed. If the flow of cash dividends from IPL to its unregulated parent companies were unrestricted, such cash flows could lower the amount of equity retained in IPL to a level that the additional debt financing proposed herein might become imprudent. In addition, as a company increases the percentage of debt in its capital structure, both its cost of equity and its cost of debt increase -- a burden that eventually would fall on ratepayers.

Id. at *22-*24.

Some of the concerns we discussed are present here, but some are not. For instance, unlike IPL, NIPSCO's capitalization is not debt-heavy, which relieves some of the concern over dividend transfers negatively affecting NIPSCO's ability to obtain financing. This Commission seeks to use restraint in creating obstacles that may be viewed by the investment community as over-regulation. Therefore, we do not adopt Dr. Wilson's ring fencing recommendations. However, as discussed previously in this Order, NIPSCO faces ongoing challenges with respect to service quality, and will need to make expenditures to deal with those issues. As we noted in Cause No. 42292, "The Commission's duty to protect the public interest requires that it look beyond the interests of any single constituency, so that a proper balance can be found between a diversity of interests." Id. at *25. We find that the conditions on dividend transfers instituted in Cause No. 42292 would be appropriate for NIPSCO.

Accordingly, the Commission finds that NIPSCO, before declaring or paying any dividend, shall file with the Commission a report detailing (1) the amount of the proposed distribution, (2) the amount of dividends distributed during the prior twelve months, (3) an income statement for the same twelve-month period, (4) the most recent balance sheet, and (5) NIPSCOs capitalization as of the close of the preceding month, as well as a pro forma capitalization giving effect to the proposed dividend, with sufficient detail to indicate the amount of unappropriated retained earnings. If within twenty (20) calendar days the Commission does not initiate a proceeding to further explore the implications of the proposed dividend, the proposed dividend shall be deemed approved. The Commission finds that the preceding approval process shall continue in effect through December 31, 2014, or further Order of the Commission, whichever occurs first.

17. Customer Surveys. Throughout the hearing, LaPorte's counsel asked questions of NIPSCO's witnesses regarding surveys of utility customers. LaPorte Witness Barbara Huston, a LaPorte County Commissioner, testified that NIPSCO should have to earn a rate increase based upon survey results, and hoped that the Commission would apply a "discount" or "deduction" to NIPSCO's authorized rate of return to reflect NIPSCO's low results in customer satisfaction surveys. Huston Direct at 2-3. In rebuttal, NIPSCO Witness Shambo testified that while perception surveys provide important input to utilities, he did not believe that a utility's return should be based upon such surveys. Shambo Rebuttal at 41. During cross-examination of Mr. Skaggs and Ms. Odum, several questions were asked regarding NIPSCO's rankings in various perception surveys and the degree to which NIPSCO was working to improve those rankings. Both Mr. Skaggs and Ms. Odum acknowledged that NIPSCO's rankings can be improved and discussed the steps NIPSCO is taking to improve customer perceptions. Ms. Odum testified about the results of two internal surveys conducted by an outside firm engaged by NIPSCO, which included 17,000 and 21,000 respondents, respectively (as compared to a J.D. Power survey that would include at most 500 customers), have reached significantly different results from the J.D. Power surveys. Tr. at D-28–D-30. Ms. Odum noted that NIPSCO received positive ratings on a number of questions, including a 73% level of agreement that NIPSCO is a positive member of the community, a 91% favorable rating in terms of reliability of service, and a 72% agreement that customers receive good value for the electric services provided. Tr. at E-67–E-68. Ms. Odum stated that these results provide various points of information for NIPSCO to consider as it works to improve customer satisfaction.

The Commission agrees that customer satisfaction is important and customer perception surveys are a useful tool in evaluating customer satisfaction, and we have assigned appropriate weight to this evidence in determining NIPSCO's cost of equity.

As NIPSCO's witnesses discussed during cross-examination on this issue, perception surveys are one data point, among many, in evaluating customers' views towards their utility and the service they are receiving. As Mr. Skaggs stated during cross-examination regarding NIPSCO's efforts to improve customer perceptions of the Company:

> I think that we continually work with our peers and look at their best practices, and I think you can look at that in our contact center, storm response activities, generation of management activities, external affairs activities. We are constantly looking at those standards through industry associations, through our peer relationships, and I'd go a step further, we certainly try to look beyond our peers. The process to make improvement is not a day process, a week process, a month process. It is like our relationship. It takes literally months, years, to rebuild that and to overcome what appears here as eight years-plus of problematic perceptions. It is going to take us a lot of time to rebuild that, and it is not going to be over just one dimension. It is going to be answering the phones; it is going to be participating in the community; it is going to be dealing with the price issue. I can assure you, myself and the team, we've worked night and day to begin moving these numbers and our own numbers.

Tr. at B-41–B-42. Likewise, Ms. Odum discussed during her cross-examination how NIPSCO has expanded its commitment to survey research and has conducted several internal surveys to better identify and understand opportunities to improve the level of customer satisfaction with NIPSCO's service. Tr. at E-27; E-66–E-68. The Commission encourages NIPSCO to continue to actively address the customer perception and satisfaction issues.

18. <u>Confidentiality</u>. NIPSCO filed six motions for protective orders and NIPSCO and the OUCC filed one joint motion for a protective order, all of which were supported by affidavits 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 and, in the case of the information subject to the joint motion, that the information was also confidential infrastructure information within the scope of Ind. Code § 5-14-3-4(b). The Presiding Officers issued docket entries and made rulings from the bench finding such information to be preliminarily confidential, after which such information was submitted under seal. NIPSCO also filed a seventh motion for protective order relating to confidential information contained in <u>Petitioner's Redirect Ex. 3-C</u>, which was granted from the bench without objection. Tr. at KK-48–KK-49. We find 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 continue to be held confidential by the Commission.

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

1. Petitioner Northern Indiana Public Service Company shall be and hereby is authorized to revise its basic rates and charges for electric utility service to provide annual gross margin revenue of $899,401,890 plus non-trackable fuel expense of $11,015,038 which on the

basis of annual electric operating expenses of $706,976,357 (net of revenues and expenses relating to trackable and non-trackable fuel and purchased power and related Utility Receipts Tax) are estimated to provide net operating income of $192,425,533. For purposes of computing the authorized net operating income for Ind. Code § 8-1-2-42(d)(3), the decrease in Petitioner's return shall be phased-in over the appropriate period of time that the Petitioner's net operating income is affected by the earnings modification as a result of the Commission's approval of this Order.

2. Petitioner shall file a new schedule of rates and charges and "proof of revenues" with the Commission's Electricity Division within thirty (30) days of this Order. That "proof of revenues" filing shall include the billing determinants and the allocation of the revenue increase as found appropriate within this Order. At such time, NIPSCO shall also file a revised cost of service study demonstrating that the new rates are consistent with the findings made herein. Copies of same shall be served upon all parties of record. Any party contesting the derivation of the rates and charges shall file its notice within ten (10) business days of the filing of the new rate schedules, proof of revenues and cost of service study. In the event any party files such a notice, the Commission shall then establish a procedural schedule regarding the compliance filing. The new schedule of rates and charges shall be effective upon filing with and approval by the Electricity Division or by Order of the Commission.

3. NIPSCO shall also file with the Electricity Division revised FAC factors in accordance with the findings herein, and such changes shall be effective simultaneously with the change in base rates authorized herein.

4. NIPSCO shall also file with the Electricity Division revised ECRM and EERM factors that eliminate costs that are being rolled into the base rate approved herein which changes shall be effective simultaneously with the new base rates.

5. Subject to adjustment to reflect the rate levels approved herein, NIPSCO's proposed Electric Tariff, revised to conform to Petitioner's Exhibit CAW-R1, including but not limited to the General Rule and Regulations set forth therein, as modified in this Order, shall be and hereby is approved to be effective simultaneously with the new base rates approved herein.

6. NIPSCO's standard form template agreement for service under Rates 526, 533 and 534 in the form of Petitioner's Exhibit CAW-R3 shall be and hereby is approved.

7. NIPSCO shall adjust its base rates to eliminate the aging workforce adjustment, emission allowance sale amortization, rate case expense amortization, the amortization of Sugar Creek deferred depreciation, and the Midwest ISO deferred cost amortization at the end of the respective adjustment or amortization periods approved herein by filing revised rate schedules with the Commission's Electricity Division.

8. NIPSCO's proposed depreciation accrual rates for electric plant and common plant as set forth in Petitioner's Exhibit JJS-2, pages 51-62, are hereby approved and authorized as modified herein. NIPSCO's depreciation rates shall not include decommissioning costs as addressed in this Order.

9. NIPSCO shall be and hereby is approved and authorized to implement an RTO Tracker and Resource Adequacy Tracker as described herein.

10. NIPSCO's proposed reclassification of electric plant as transmission or distribution pursuant to FERC's Seven-Factor Test is hereby approved.

11. The information submitted under seal in this Cause pursuant to motions for protective orders is determined to be confidential and exempt from public access and disclosure pursuant to Ind. Code § 24-2-3-2 and § 5-14-3-4.

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

HARDY, ATTERHOLT, MAYS, AND ZIEGNER CONCUR; LANDIS ABSENT:
APPROVED: AUG 25 2010

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

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STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY REQUESTING THE INDIANA UTILITY REGULATORY COMMISSION TO APPROVE AN ALTERNATIVE REGULATORY PLAN PURSUANT TO IND. CODE § 8-1-2.5-1, *ET SEQ.*, FOR THE OFFERING OF ENERGY EFFICIENCY CONSERVATION, DEMAND RESPONSE AND DEMAND-SIDE MANAGEMENT PROGRAMS AND ASSOCIATED RATE TREATMENT INCLUDING INCENTIVES IN ACCORDANCE WITH IND. CODE §§ 8-1-2.5-1 *ET SEQ.* AND 8-1-2-42(a); AUTHORITY TO DEFER PROGRAM COSTS ASSOCIATED WITH ITS AUTOMATED METER PROGRAM; AUTHORITY TO IMPLEMENT NEW AND ENHANCED ENERGY PROGRAMS; AUTHORITY TO IMPLEMENT AN FAC ALLOCATOR MECHANISM APPLICABLE TO THE FUEL COST ADJUSMENT CLAUSE MECHANISM; AND APPROVAL OF MODIFICATION OF THE FUEL ADJUSTMENT CLAUSE EARNINGS AND EXPENSE TESTS.	**CAUSE NO. 43618** **APPROVED:** MAY 25 2011

<u>BY THE COMMISSION</u>:
David E. Ziegner, Commissioner
Aaron A. Schmoll, SeniorAdministrative Law Judge

On December 4, 2008, Northern Indiana Public Service Company ("NIPSCO") filed its *Verified Petition* initiating this proceeding, along with supporting testimony and exhibits. On February 6, 2009, a *Petition to Intervene* was filed by the NIPSCO Industrial Group ("Industrial Group"), and a *Petition to Intervene* was filed on February 10, 2009 by the City of Hammond, Indiana ("Hammond"). Also on February 10, 2009, a Prehearing Conference and Preliminary Hearing was held in Room 222 of the PNC Center, 101 W. Washington Street, Indianapolis, Indiana, commencing at 10:00 a.m. At the Prehearing Conference, the *Petitions to Intervene* of Industrial Group and Hammond were granted on the record and the parties agreed to various procedural dates to govern this proceeding that were memorialized in a Prehearing Conference Order approved by the Commission on February 25, 2009.

On February 27, 2009, the Indiana Office of Utility Consumer Counselor ("OUCC"), together with Hammond and the Industrial Group filed a *Joint Motion to Stay Portion of Petitioner's Case* seeking a stay of portions of the relief requested by NIPSCO pending the outcome of its general rate proceeding in Cause No. 43526. After submission of NIPSCO's *Response* and a *Reply* from the moving parties, the Commission granted a stay of that portion of NIPSCO's case related to modification to NIPSCO's statutory Fuel Adjustment Clause ("FAC") filings pending a Final Order in Cause No. 43526 in a Docket Entry entered by the presiding officers on April 7, 2009.

On April 28, 2009, Commission issued a Docket Entry with a revised procedural schedule and the Industrial Group filed an *Emergency Motion for Extensions of Time to File Testimony*. On May 5, 2009, the Citizens Action Coalition, Inc. ("CAC") filed a *Petition to Intervene*, which the Commission granted without objection on May 15, 2009. The OUCC, Industrial Group and Hammond filed testimony on May 22, 2009. The CAC filed cross-responsive testimony on June 9, 2009.

NIPSCO filed rebuttal testimony on June 19, 2009. On July 9, 2009, NIPSCO and the OUCC filed a *Joint Motion to Continue the Evidentiary Hearing*, which the Commission granted in a Docket Entry July 10, 2009. The hearing was continued to September 23, 2009 at 9:30 a.m. On September 19, 2009, NIPSCO filed its *First Set of Corrections* and a *Motion of Change of Witness and Submission of Direct and Rebuttal Testimony of Timothy R. Caister*. NIPSCO filed an *Unopposed Joint Motion to Continue the Evidentiary Hearing* on September 21, 2009 and the Commission issued a Docket Entry on September 22, 2009 continuing the hearing to October 1, 2009.

On September 28, 2009, NIPSCO, CAC, Hammond and the OUCC filed a *Second Joint Motion for Stay* and the Industrial Group filed an *Objection to Motion for Stay and in the Alternative Motion to Dismiss Petitioner's Case* on September 29, 2009. In response to the *Motion* and *Response*, the Commission issued a Docket Entry on September 29, 2009 establishing an Attorneys' Conference on February 10, 2010.

The Commission issued a Docket Entry on March 5, 2010 establishing a revised procedural schedule. On March 16, 2010, NIPSCO filed its revised case-in-chief. The Industrial Group, OUCC, and CAC filed direct testimony on May 5, 2010. On June 2, 2010, the OUCC filed a *Notice of Intent Not to File Cross-Reply Testimony*. On June 18, 2010, NIPSCO filed its rebuttal case.

Pursuant to notice duly given and published as required by law, and duly incorporated into the record and placed in the official files of the Commission, the Commission held an evidentiary hearing in this Cause starting at 9:30 a.m. on June 30, 2010 in Room 222 of the PNC Center, 101 W. Washington Street, Indianapolis, Indiana. At the hearing, the pre-filed direct and rebuttal testimony and exhibits of Petitioner's witness Kevin A. Kirkham along with the testimony of CAC witness Grant Smith, Industrial Group witness Nicholas Phillips, and OUCC witness Gregory Foster were admitted into the evidentiary record without objection. No members of the rate paying public appeared or participated at the hearing.

Based on the applicable law and evidence of record, the Commission now finds as follows:

1. **Notice and Jurisdiction.** Due, legal, and timely notice of the public hearings held in this Cause was given and published by the Commission as required by law. NIPSCO is a public utility within the meaning of Ind. Code § 8-1-2-1, and provides electric utility service to customers in a Commission approved service territory in the State of Indiana. The Commission accordingly has jurisdiction over the parties and the subject matter of this Cause.

2. **Relief Requested.** In its revised case-in-chief, NIPSCO only seeks approval of its Demand Side Management Adjustment ("DSMA") mechanism as part of its approved electric rate tariff. The DSMA is a tracking mechanism that provides for recovery of program expenses associated with Commission-approved DSM programs, including lost margins and performance incentives. The Commission notes that NIPSCO separately seeks approval of specific Core and Core Plus programs and authority to defer DSM costs in its filing in Cause No. 43912.

3. **Evidence Presented.**

A. **NIPSCO Direct Testimony.** NIPSCO submitted testimony from its Director, Energy Efficiency, Kevin A. Kirkham, who has responsibility over the implementation of DSM and Energy Efficiency ("EE") programs for NIPSCO. He testified that NIPSCO proposes implementation of the DSMA in this proceeding as the framework for the recovery of Commission-approved DSM Costs, including expenses for administration, marketing, evaluation, outside services, consultants, equipment purchases and information systems modifications as well as for lost margins and incentives approved by the Commission. He testified that the proposed DSMA Rider would be applicable to NIPSCO Rates 811, 812, 813, 820, 821, 822, 823, 824, 826, 832, 833, 834, 836, 841, 844, 845, Rider 846, and Rate Code 847. (Kirkham Direct at 2.)

Mr. Kirkham's Direct Testimony also explained the calculation of the DSMA for each class as:

$$\text{Adjustment Factor}_{Rate} = \quad \text{Sum of} \quad \frac{DSM_p \text{ X } Cust_{Rate}}{Cust_p \text{ X } BE_{Rate}} \quad \text{for all programs (P)}$$

where:

1. "DSM_p" is the estimated DSM Costs for the current six (6) month period for each DSM/EE program (P). Subject to Commission approval, DSM Costs shall include all program costs, incentives, and net lost margins.
2. "$Cust_{Rate}$" is the estimated number of customers in the rate eligible for DSM/EE program (P).
3. "$Cust_p$" is the sum of the $Cust_{Rate}$ for all rates eligible for DSM/EE program (P).
4. "BE_{Rate}" is the estimated jurisdictional billing kWh for each rate for the

current six (6) month period.

(Kirkham Direct at 3-4.) He explained that NIPSCO proposes that each approved DSMA factor would be applicable for six months until superseded by a subsequent factor, and each factor proposed would be adjusted for taxes and for the reconciliation of estimated and actual costs from the same six month period in the previous year. (Kirkham Direct at 4-5.) He testified that the DSMA for each rate would be adjusted to provide for recovery of utility receipts tax and other revenue-based taxes, in addition to the reconciliation of actual with estimated DSM costs, kWh sales and customer participation level. (Kirkham Direct at 4.) Mr. Kirkham sponsored NIPSCO's proposed Appendix H and Rule 52 to memorialize the DSMA and its applicability, and also proposed the addition of specific language to each tariff rate to which the DSMA would apply. (Kirkham Direct at 5, Proposed Appendix H and Rule 52.)

Mr. Kirkham testified that NIPSCO was requesting authority to recover lost margins associated with its approved DSM programs and described the methodology to be used for the calculation of lost margins. He testified that lost margins will be forecasted for a six (6) month period consistent with the other components of the DSMA, and would be reconciled to actual participation at the same time that other reconciliation takes place for the same period. He explained that the total lost margins for each program would be based on a ten (10) year period of reduced kWh consumption and kW demand reductions following installation based on the weighted average life of the program measures. Mr. Kirkham testified that estimates of kWh consumption and kW demand reductions per participant and the number of participants for each program would be determined in future NIPSCO DSM proceedings, and estimated participants for each program then allocated among the individual rate classes based upon the ratio of the annual historical kWh consumption within their rate class. He explained that allocated participants by rate would then be multiplied by the kWh consumption and kW demand reductions per participant to determine the total kWh consumption and kW demand amounts by rate within each program. The amounts by program would then be totaled for each rate and multiplied by the margin rates per kWh and kW from NIPSCO's last general electric rate case to arrive at a lost margin allocation for each rate. (Kirkham Direct at 6.) He testified that NIPSCO proposes to use per kWh and per kW margins approved by the Commission in its pending electric rate case in Cause No. 43526 as the basis for its calculation. (Kirkham Direct at 6-7.)

Mr. Kirkham clarified that NIPSCO only proposed approval of tariff language in this proceeding and not any specific level of costs, lost margins, or incentives. He explained that all amounts to be recovered through the tariff framework would be based on Commission-approved programs proposed in a future proceeding. He noted that NIPSCO was completing a market potential study in support of a portfolio of proposed programs consistent with the Commission's December 9, 2009 Order in Cause No. 42693 ("Phase II Order") and also intends to explore opportunities for combining gas and electric focused programs. (Kirkham Direct at 7-8.)

B. OUCC Direct Testimony. OUCC witness Greg A. Foster testified that the proposed tariff changes would enable NIPSCO to recover direct and indirect costs incurred for the development, implementation, approval and oversight of future proposed DSM programs and budgets, after those future proposed DSM programs and budgets are approved by the Commission in a future proceeding. NIPSCO proposes a tariff-based recovery structure to be put in place after necessary Commission approvals are obtained for company-specific and/or statewide generic DSM programs and budgets. Until that time, NIPSCO's proposed DSM tracker would be set at zero dollars ($0.00). The proposed tracker would allow NIPSCO to recover Commission-approved estimated *pro forma* DSM program costs and other approved elements of recovery through a DSM tracking mechanism, with semi-annual reconciliations, allowing the Commission to review and approve forward-looking adjustments to NIPSCO's DSM tracker at regular 6-month intervals.

Mr. Foster acknowledged that NIPSCO expects to file a completed market potential study ("MPS") in the near future, with testimony outlining NIPSCO's proposed DSM programs, implementation plans, budgets for Core DSM programs, and any other elements of recovery for which NIPSCO seeks Commission approval (*e.g.*, lost margins and shareholder incentives for non-Core DSM programs).

Mr. Foster explained that, since NIPSCO has not yet proposed specific DSM programs or specific dollar amounts to be recovered, the OUCC could not evaluate the reasonableness or necessity of proposed expenditures or any other proposed elements of recovery. The nature of Petitioner's evidence necessarily limits the issues that can be reviewed and addressed at this time. Therefore, Mr. Foster's testimony was limited to the issue of whether NIPSCO should be permitted to establish a tariff tracking mechanism to use in the future to recover DSM program costs and any other related elements of recovery ultimately approved by the Commission in future proceedings.

Mr. Foster testified that NIPSCO's proposed DSM tracker methodology and its proposed 6-month true-up mechanism are consistent with similar tracking mechanisms the Commission has approved for other Indiana energy utilities. However, as to other utilities, the tracking mechanisms were proposed and approved at the same time the Commission approved specific DSM programs and budgets. (Foster Direct at 4.) Mr. Foster explained that, before it can take advantage of the proposed DSM tracking mechanism, NIPSCO must seek and obtain Commission approval of NIPSCO's proposed DSM programs and associated program budgets. The limited nature of the approval currently sought for Petitioner's proposed tracking mechanism would allow NIPSCO to recover future expenses following Commission hearing and approval, subject to true-up at regular six-month intervals.

Mr. Foster testified that the OUCC does not oppose the establishment of a retail tariff tracking mechanism initially set at zero dollars ($0.00) as a placeholder for future approved NIPSCO DSM programs. However the OUCC specifically reserves its right to evaluate the reasonableness, cost-effectiveness and necessity of NIPSCO's future DSM program and budget proposals, including proposed program costs and any claims for lost margins and shareholder or management incentives, until such time as NIPSCO's future DSM proposals are approved by the Commission. Mr. Foster recommended that NIPSCO be allowed to add a DSM tracking mechanism to its retail tariff to be used to recover amounts approved by the Commission in future DSM proceedings. (Foster Direct at 5.)

C. Industrial Group Direct Testimony. In testimony submitted on behalf of the NIPSCO Industrial Group, Mr. Nicholas Phillips, Jr. stated that the cost allocation mechanism proposed by NIPSCO appeared to be appropriate. (Phillips Direct at 4.) He testified that, while trackers should be kept to a minimum, if one is approved, it should be based on known costs. (Phillips Direct at 7.) He opposed the broad categories of costs NIPSCO proposed to include in the DSMA, including direct and indirect costs, lost margins, and incentives, because those costs are unknown at this time. Mr. Phillips recommended that the only costs that should be approved at this time are the third-party administrator costs for the Core Programs. Mr. Phillips argued that customers should be able to implement voluntary, self-directed programs and that these programs should be encouraged. (Phillips Direct at 8.)

If the Commission were to adopt the lost margin component, Mr. Phillips recommended that lost margins be limited to verified metered sales reductions that are attributable to NIPSCO's programs and that there be no lost margins if sales levels are higher than the levels used to establish the current base rates in effect. Mr. Phillips further recommended that any lost margins granted should be net of fuel and variable operating and maintenance expenses consistent with the variable operations and maintenance allowance embedded in base rates in NIPSCO's most recent rate case.

D. CAC Direct Testimony. Mr. Grant Smith testified on behalf of the CAC. Mr. Smith testified that, because NIPSCO is required to participate in the offering of the "core" DSM programs as provided by the Phase II Order, it is appropriate to approve program costs related to that offering. (Smith Direct at 2.) He stated that it was not appropriate to recover unidentified costs, including costs for programs that have not yet been approved by the Commission, or costs related to lost margins, incentives or shared savings at this time. (Smith Direct at 2-3.) Mr. Smith testified that approval of a tariff for recovery of lost margin or utility incentives should only be done in the context of a review of the programs and that NIPSCO needs to implement an evaluation plan as indicated in the Commission's rules. (Smith Direct at 4.) Regarding incentives, Mr. Smith testified that, once they are requested by NIPSCO, the Commission should not approve an incentive structure that permits a reward to be earned by NIPSCO if the company fails to exceed 100% of its planned demand and energy savings. (Smith Direct at 6.) Mr. Smith also stated that lost margin recovery, if allowed, should only be for non-core DSM programs and should not include lost margins related to other causes. *Id.*. According to Mr. Smith, the Commission should direct NIPSCO to work through a collaborative process using the existing stakeholder group or through a subcommittee of the DSM Coordination Committee. *Id.*

E. NIPSCO Rebuttal Testimony. Mr. Kirkham submitted Rebuttal testimony that responded to issues raised by witnesses Foster, Phillips, and Smith. He testified that while he agreed with Mr. Phillips that voluntary energy efficiency efforts by large customers should be encouraged, such efforts would be insufficient for NIPSCO to meet the goal of a 2% reduction in gross annual energy sales by 2019 as identified in Phase II Order, and noted that the Commission had required implementation of certain Core programs. Mr. Kirkham testified that while NIPSCO considers cost-effectiveness of energy efficiency measures implemented directly by customers, utility programs must be evaluated on a system-wide basis for cost effectiveness. (Kirkham Rebuttal at 2.)

Mr. Kirkham testified that the OUCC, Industrial Group and CAC each had agreed with some parts of NIPSCO's tariff proposal, with Mr. Foster of the OUCC stating that the proposed DSMA was consistent with similar mechanisms approved by the Commission, Mr. Phillips of the Industrial Group noting that the allocation mechanism proposed appeared to be appropriate, and Mr. Smith of the CAC testifying that a tariff mechanism for the recovery of direct program costs was reasonable. (Kirkham Rebuttal at 3.) He also noted that NIPSCO's filing in Cause No. 43912 addressed a variety of concerns tied directly to the specific programs whose costs would be eligible for recovery through the DSMA when approved, including the need to prove the merit of the specific programs, explanation of the application of lost margin calculations, and details concerning specific costs and incentives for which recovery is proposed. (Kirkham Rebuttal at 3-4.)

Mr. Kirkham disagreed with Mr. Phillips's opposition to the use of forecasted costs, and explained that the Commission had previously approved similar mechanisms for Indianapolis Power & Light in Cause No. 43623. He added that other regulatory tracking mechanisms such as FAC and Environmental Cost Recovery mechanisms routinely use forecasted data that is ultimately subject to a true-up in subsequent proceedings. He added that specific DSMA factors will be based on a market potential study that incorporates information from actual cost and savings experiences with other programs. (Kirkham Rebuttal at 4.) Finally, Mr. Kirkham asserted that the true-up provisions of the proposed DSMA would allow for an appropriate matching of actual costs with recovery, thereby providing a consistent pricing signal to customers and mitigating any adverse impact associated with the programs on the utility. (Kirkham Rebuttal at 5.)

Mr. Kirkham agreed with Mr. Phillips that NIPSCO should make an offset to its lost margin calculation for avoided variable operation and maintenance expenses, but disagreed with both Mr. Phillips' and Mr. Smith's positions on the recovery of lost margins and incentives. He testified that lost margin and performance incentives give NIPSCO the ability to provide DSM programs on a comparable financial basis with supply side options. He testified that lost margin recovery on a per unit basis is appropriate, and that its proposed calculation was consistent with the Commission's Rules and provides recovery of those dollars in a manner solely dependent on the energy savings achieved. (Kirkham Rebuttal 5-6.)

4. Alternative Regulatory Relief. While the *Verified Petition* in this proceeding proposed approval of an Alternative Regulatory Plan pursuant to the provisions of the Alternative Utility Regulatory Act, Ind. Code ch. 8-1-2.5, the evidence admitted into the record at the evidentiary hearing contains nothing proposing or supporting such relief. We accordingly find that the provisions of Ind. Code § 8-1-2.5, are not applicable to the relief requested.

5. Commission Discussion and Findings. The issues presented in this proceeding are framed by the Commission's Demand Side Management Rules, 170 IAC 4-8, and by its Phase II Order.

A. Legal Consideration of DSM Proposals. The Commission has developed a regulatory framework that allows a utility to meet long term resource needs with both supply-side and demand-side resource options in a least cost manner. As part of its Integrated Resource Plan ("IRP"), an electric utility must consider alternative methods of meeting future demand for electric service, including a comprehensive array of demand side measures that provide an opportunity for all ratepayers to participate in DSM, including low-income residential ratepayers.

In 1995, the Commission adopted the DSM Rules providing guidelines for DSM cost recovery. The DSM Rules were specifically designed to assist the Commission in its administration of the Utility Powerplant Construction Act, Ind. Code ch. 8-1-8.5, and to facilitate increased use of DSM as part of the utility resource mix. As further set forth in 170 IAC 4-8-3(a), the purpose of the DSM Rules was to:

> (a) . . . [provide] a regulatory framework that allows a utility an incentive to meet long term resource needs with both supply-side and demand-side resource options in a least-cost manner and ensures that the financial incentive offered to a DSM program participant is fair and economically justified. The regulatory framework attempts to eliminate or offset regulatory or financial bias against DSM, or in favor of a supply-side resource, a utility might encounter in procuring least-cost resources. The commission, where appropriate, will review and evaluate the existence and extent of regulatory or financial bias.
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> (c) To ensure a utility's proposal is consistent with acquiring the least-cost mix of demand-side and supply-side resources to reliably meet the long term electric service requirements of the utility's customers, the commission, where appropriate, will review and evaluate, as a package, the proposed DSM programs, DSM cost recovery, lost revenue, and shareholder DSM incentive mechanisms.

B. Commission Order in Phase II of the DSM Investigation. In its Phase II Order, the Commission found that jurisdictional electric utilities, of which NIPSCO is one, are required to offer certain core DSM programs ("Core Programs") to all customer classes and market segments. The Core Programs are to include the following: (1) Home energy audit program, (2) Low income weatherization program, (3) Residential lighting program, (4) Energy efficient schools program, and (5) Commercial and Industrial program. To implement these programs, electric utilities are required to pursue coordinated marketing, outreach and consumer education strategies on a statewide basis.

The Commission also determined that an Independent Third Party Administrator should be utilized by the electric utilities to oversee the administration and implementation of the Core Programs. In addition, a DSM Coordination Committee has been formed to address DSM program oversight generally within the State of Indiana. The Commission also found that a single statewide evaluation protocol was necessary in order to track achievement with DSM goals. Consequently, jurisdictional electric utilities are required to contract with an independent entity to conduct the EM&V with respect to the Core Programs.

Finally, the Commission found that the associated ratemaking and cost recovery issues associated with an electric utility's DSM programs should be addressed on a case by case basis in individual utility proceedings.

C. **NIPSCO's Proposed DSMA.** This proceeding was initiated well in advance of the Phase II Order, and ultimately evolved to only propose approval of the tariff provisions necessary for NIPSCO to implement the recovery of any costs, lost margins, and/or performance incentives associated with Commission-approved DSM programs. NIPSCO has initiated a second proceeding in Cause No. 43912 in which it seeks approval of specific Core and Core Plus programs consistent with the Phase II Order including the costs, lost margins and performance incentives to be recovered. As a result, our inquiry here is limited to a review of the proposed tariff mechanism.

170 IAC 4-8-5(b) provides that "[t]he commission shall determine the cost recovery mechanism for a demand-side management program when the demand side management program is submitted for commission approval." In this instance, NIPSCO is proposing the mechanism for cost recovery in one proceeding, while the underlying programs and associated costs, lost margins, and performance incentive levels and methodology are proposed in another. By proposing to put the DSMA in place prior to the approval of the underlying programs (and thus with a tracking factor of zero), NIPSCO has elected to put the mechanism for cost recovery in place in anticipation that the Commission will ultimately approve its programs in Cause No. 43912. Should the Commission determine that the DSMA is not the appropriate mechanism for recovery of costs for one or more of NIPSCO's proposed programs, the Commission may order different relief based on the evidence presented in future DSM proceedings.

The Commission's DSM Rules authorize a variety of cost recovery mechanisms for DSM related costs, including "[a] cost recovery mechanism proposed by the utility, other parties, or the commission." 170 IAC 4-8-5(a)(5). NIPSCO proposes the DSMA as a tracking mechanism that provides for the implementation of a tracking factor on a semi-annual basis, with estimated costs, customer numbers and kWh usage reconciled with actual information for each rate class subject to its provision in the same six-month period in the succeeding year. NIPSCO's proposal is similar in many respects to the DSM/EE Program Cost Rider approved by the Commission for Indiana Michigan Power Company for the recovery of DSM costs in Cause No. 43306, and is also similar to the mechanisms previously approved for Vectren Energy Delivery of Indiana d/b/a Southern Indiana Gas & Electric Company ("Vectren") in Cause No. 43111 (August 15, 2007) and for Indianapolis Power & Light Company in Cause No. 43623 (February 10, 2010). We accordingly find that NIPSCO's proposed DSMA is consistent with the Commission's DSM Rules and with mechanisms implemented for other Indiana electric utilities and should be approved, subject to the findings in this Order.

The methodology proposed by NIPSCO to allocate DSM costs among customer classes appears reasonable based on the evidence of record available at this time. We are cognizant of the concerns related to performance incentives and lost margins, but find that those concerns would be more appropriately addressed in the context of the evaluation of individual DSM programs in Cause No. 43912, since NIPSCO has proposed no specific levels of program costs, lost margins or performance incentives for recovery in this proceeding. Therefore, specific DSMA recovery details will be decided in future DSM proceedings related to company-specific or state-wide generic DSM programs approved for implementation by NIPSCO.

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

1. The Demand Side Management Adjustment mechanism proposed by NIPSCO is approved, subject to the findings in Paragraph 5 of this Order.

2. NIPSCO shall submit its proposed DSMA tariff to the Commission's Electricity Division, consisting of its proposed Appendix H and Rule 52, along with amended tariff sheets for Rates 811, 812, 813, 820, 821, 822, 823, 824, 826, 832, 833, 834, 836, 841, 844, 845, Rider 846 and Rate Code 847.

3. Consistent with the findings in Paragraph 5 of this Order, the DSMA factor shall remain at zero dollars ($0.00) until otherwise ordered by the Commission in future DSM proceedings.

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

ATTERHOLT, BENNETT, MAYS AND ZIEGNER CONCUR; LANDIS ABSENT:

APPROVED: MAY 25 2011

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

ORIGINAL

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY FOR APPROVAL OF DEMAND SIDE MANAGEMENT ADJUSTMENT FACTORS FOR ELECTRIC SERVICE FOR THE BILLING CYCLES FOR THE MONTHS OF JANUARY THROUGH JUNE 2016 IN ACCORDANCE WITH THE ORDER OF THE COMMISSION IN CAUSE NO. 44496.	)	CAUSE NO. 43618 DSM 9 APPROVED: DEC 16 2015

ORDER OF THE COMMISSION

Presiding Officers:
James F. Huston, Commissioner
Loraine L. Seyfried, Administrative Law Judge

On September 28, 2015, Northern Indiana Public Service Company ("NIPSCO" or "Petitioner") filed its semi-annual request for Commission approval of Demand Side Management Adjustment ("DSMA") factors for electric service to be applicable for bills rendered during the billing cycles of January through June 2016. On September 28, 2015, Petitioner filed its case-in-chief including direct testimony and exhibits supporting the proposed DSMA factors and the underlying costs for which Petitioner seeks cost recovery.

On November 9, 2015, the Indiana Office of Utility Consumer Counselor ("OUCC") filed its case-in-chief testimony. Petitioner filed rebuttal testimony and exhibits on November 19, 2015.

An evidentiary hearing was held on December 1, 2015 at 9:30 a.m. in Room 224 of the PNC Center, 101 West Washington Street, Indianapolis, Indiana. At the hearing, the evidence of NIPSCO and the OUCC was admitted into the record without objection and all parties waived cross-examination of witnesses. No members of the general public appeared or participated at the hearing.

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

1. Notice and Jurisdiction. Notice of the 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. The Commission's May 25, 2011 Order in Cause No. 43618 authorized NIPSCO to seek recovery of costs associated with its Demand Side Management ("DSM") program through a semi-annual adjustment mechanism. Under Ind. Code § 8-1-2-42, the Commission has jurisdiction over changes in Petitioner's schedules of rates and charges. Therefore, the Commission has jurisdiction over Petitioner and the subject matter of this Cause.

2. **Petitioner's Characteristics.** Petitioner is a public utility organized and existing under the laws of the State of Indiana and having its principal office at 801 East 86th Avenue, Merrillville, Indiana. Petitioner renders electric public utility service in the State of Indiana and owns, operates, manages, and controls, among other things, plant and equipment within the State used for the generation, transmission, distribution, and furnishing of electric public utility service to the public within its assigned service territories.

3. **Background.** On May 25, 2011, the Commission issued an Order in Cause No. 43618 approving NIPSCO's request for approval of Rule 52 of the General Rules and Regulations (now Rider 683 – Adjustment of Charges for Demand Side Management Adjustment Mechanism and Appendix G – Demand Side Management Adjustment Mechanism Factor ("DSMA Mechanism").

On November 12, 2014, the Commission issued an Order in Cause No. 44496 granting NIPSCO's request for (1) approval of electric DSM programs for the term of January 1, 2015 through December 31, 2015 ("2015 DSM Program"), (2) authority to recover associated start-up, implementation, and administrative costs along with costs associated with the evaluation, measurement, and verification ("EM&V") of those programs ("program costs") associated with the 2015 DSM Program through the DSMA Mechanism, (3) authority to defer expenses associated with the 2015 DSM Program that are incurred until such amounts are recovered through rates; (4) authority to recover lost revenues associated with the 2015 DSM Program as well as lost revenues associated with previous programs years, including those lost revenues associated with prior programs that are not included in the 2015 DSM Program through the DSMA Mechanism, and (5) authority to defer lost revenues associated with the 2015 DSM Program and lost revenues for previous program years, including DSM programs previously offered by subsequently discontinued, through the DSMA Mechanism, until such amounts are recovered through rates.

4. **Requested Relief.** Petitioner requests Commission approval of DSMA factors to be effective for bills rendered during the billing cycles of January through June 2016. The initial factors proposed in this proceeding included estimated costs from January through June 2016 and reconciled the actual costs for the period January through June 2015. The initially proposed factors also included recovery of projected lost margins and performance incentives for the period January through June 2016 and the annual reconciliation of lost margins for the period January 2014 through December 2014, half of which will be recovered in this filing and the other half will occur in NIPSCO's next DSM filing (i.e., Cause No. 43618 DSM 10). For purposes of calculating the estimated costs for January through June 2016, NIPSCO assumed approval of its pending request in Cause No. 44634 concerning its proposed electric DSM programs ("2016 DSM Program") and associated cost recovery. In its rebuttal filing, Petitioner modified its request to remove its request for recovery of estimated DSM program costs for the period January through June 2016 and the projected lost margins and performance incentives related to the proposed 2016 DSM Program.

Petitioner also requests continued authority to defer as a regulatory asset or regulatory liability the over- and under-recoveries of projected DSM program costs and lost margins incurred implementing the DSM programs prior to the time the Commission issues an order authorizing Petitioner to recognize these costs through the ratemaking process. NIPSCO will defer these costs on the balance sheet as a regulatory asset in Account 182.3 – Regulatory Asset or a regulatory liability in Account 254 – Other Regulatory Liabilities depending on the net balance of program costs.

5. **Implementation of DSM Programs.** NIPSCO's witness Victoria A. Vrab, Director of Demand Side Management Programs, sponsored Petitioner's Exhibit No. 2-B, the scorecard for NIPSCO's DSM program for the period January 2015 through June 2015 and described the performance as follows:

- Residential Lighting Program – As of June 30, 2015, this program achieved 41% of its savings goal. As of August, NIPSCO forecasted that this program is on track to achieve 100% of its savings goal by year end.

- Residential Home Energy Assessment & Weatherization Program – As of June 30, 2015, this program achieved 22% of its savings goal. As of August, NIPSCO forecasted this program to achieve 75% of its savings goal by year end. NIPSCO continues to work with CLEAResult and its Oversight Board ("OSB") to encourage customer participation and specific areas of the service territory in which to focus these efforts.

- Residential Income Qualified Weatherization Program – As of June 30, 2015, this program achieved 26% of its savings goal. As of August, NIPSCO forecasted this program will achieve 90% of its savings goal by year end. In July, the OSB elected to introduce programmable thermostats to the program to assist with achievement of the goal.

- Energy Efficiency Rebate Program – As of June 30, 2015, this program, which has been highly successful because of the measure list included for rebates, achieved 63% of its savings goal. As of August, NIPSCO forecasted this program to achieve 100% of its savings goal by year end.

- School Education Program – As of June 30, 2015, this program achieved 101% of its savings goal.

- Residential New Construction Program – As of June 30, 2015, this program achieved 29% of its savings goal. As of August, NIPSCO forecasted this program to achieve 90% of its savings goal by year end. In response to feedback from the OSB, NIPSCO lifted the per-builder cap on the program, which has increased participation.

- Residential Home Energy Conservation Program – As of June 30, 2015, this program achieved 54% of its savings goal. NIPSCO forecasted that this program is on track to achieve 100% of its savings goal by year end.

- Commercial and Industrial ("C&I") Prescriptive Rebate Program – As of June 30, 2015, this program achieved 2% of its savings goal. As of August, NIPSCO forecasted this program to achieve 50% of its savings goal by year end.

NIPSCO continues to work with Franklin Energy and its OSB to facilitate goal attainment by year end and is already working with Lockheed Martin to prevent such a delay in program offerings in 2016.

- <u>C&I Custom Program</u> – NIPSCO uses a "pipeline" of anticipated savings to better align the program expectations. As of June 30, 2015, this program achieved 8% of its savings goal. Based on on-going evaluation of the progress of projects in the pipeline, as of August, NIPSCO forecasted this program to achieve 100% of its savings goal by year end.

- <u>C&I Small Business Direct Install Program</u> – As of June 30, 2015, this program achieved 9% of its savings goal. Because of an increase in interest in the program by trade allies, as of August, NIPSCO forecasts this program to achieve 100% of its savings goal.

- <u>School Audit and Direct Install Program</u> – As of June 30, 2015, this program achieved 0% of its savings goal. However, many of the school audits took place during the summer months when classes were not in session as well as at the beginning of the school year. Because of this, as of August, NIPSCO forecasted this program to achieve 100% of its savings goal by year end.

- <u>A/C Cycling Program</u> – As of June 30, 2015, this program achieved 0% of its savings goal because no events had been called and NIPSCO only accrues savings once an event is called. The A/C Cycling Program was closed to new participants in 2015.

6. <u>Inclusion of Cost Related to 2016 DSM Program</u>. OUCC witness Crystal Thacker, Utility Analyst in the OUCC's Electric Division, suggested that NIPSCO should not include in the calculation of its proposed DSMA factors any costs related to the 2016 DSM Program currently pending approval in Cause No. 44634 until after the Commission issues an order in that Cause.

In his rebuttal testimony, NIPSCO witness Thomas S. Sibo, Manager, Regulatory Support and Analysis in the Rates and Regulatory Finance Department, testified NIPSCO is willing to comply with this recommendation. Mr. Sibo testified NIPSCO recalculated its DSMA factors to include reconciliation of 2014 lost margins and 2015 program costs. In addition, NIPSCO included in the factor calculations the projected lost margins relating to measures installed on or before December 31, 2015, as previously approved by the Commission in its Orders in Cause Nos. 44154 and 44496. Mr. Sibo sponsored Petitioner's Exhibit No. 2-A, Revised Attachment A.

Mr. Sibo testified once an order is received in Cause No. 44634, NIPSCO proposes to file Phase 2 schedules in this Cause that recalculate the factors to include 2016 approved DSM program costs. All parties would be permitted to review the revised schedules, perform discovery, and file comments on the proposed DSMA factors on an expedited basis. Then, a hearing would be scheduled, after which new DSMA factors would be approved.

Mr. Sibo testified NIPSCO revised the schedules to remove any costs relating to the associated energy efficiency costs included in its proposed 2016 DSM Program currently pending in Cause No. 44634. Specifically, NIPSCO adjusted Schedule 1.1 to remove the projected program costs during the period January through June 2016 totaling $3,973,531. NIPSCO adjusted Schedule 1.2 to remove the projected performance incentives relating to the period January through June 2016 totaling $265,795. The effect of these two changes removes all costs from Schedule 2.1 and brings the allocation of these costs to zero. NIPSCO adjusted Schedule 3.4 to remove 1,468 of kW demand savings and 4,702 of MWh energy savings associated with the projected measures to be installed for the period January through June 2016. The removal of the demand and energy savings from Schedule 3.4 brings the projected lost margins (for measures projected to be installed from January through June 2016) shown in Schedules 4.4 and 5.4 to zero. The overall effect of these changes on the proposed DSMA factors is shown on Schedule 7. Columns (c), (j), and (n) now show there are no allocation included in the Total Allocation of DSM Costs shown in Column (p). This results in the overall revenue requirement changing from $13,051,849 to $8,487,113.

7. <u>Recovery and Reconciliation of Program Costs and Revenues</u>. Petitioner's Exhibit No. 2-A, Revised Attachment A, Schedule 1.1 shows a breakdown of projected and reconciled costs for the recovery period of January through June 2015. The DSMA factors proposed in this proceeding reconcile program costs incurred for the period January through June 2015.

Ms. Vrab provided an explanation of the exhibit supporting Schedule 1. She stated that Petitioner's Exhibit No. 2-C is the work product that feeds into Schedule 1 showing the actual costs incurred from January through June 2015 reconciled against the prior forecast for the same period in Cause No. 43618 DSM 7 ("DSM 7").

Ms. Vrab testified the projected costs for the period January through June 2015 were $8,889,288 and the actual costs incurred were $6,079,966 resulting in an over-recovery of $2,809,322. She stated that the majority of the over-recovery is associated with the C&I Prescriptive Rebate Program and the Residential Home Energy Assessment and Weatherization Program contributed as well.

Ms. Vrab testified that for those customers who opted out effective July 1, 2014 ("Opt Out 1") or effective January 1, 2015 ("Opt Out 2"), NIPSCO removed their volumes from the program when determining potential participation. She noted the deadline for the next opt out period is November 15, 2015. Since the deadline for Opt Out 3 had not passed at the time of filing, NIPSCO worked with its largest customers to gauge potential interest and made adjustments to remove any volumes where there was high probability that the customer would opt out. NIPSCO also removed any customers who had submitted opt out forms prior to the November 15, 2015 deadline. In Mr. Sibo's rebuttal testimony, NIPSCO created an Opt Out 3 category for those customers who had submitted opt out forms prior to the November 15, 2015 deadline and made changes to all schedules where volumes or customer counts were used to allocate costs.

As shown on Petitioner's Exhibit No. 2-A, Revised Attachment A, Schedule 1.1, taking the actual EM&V costs for the period January through June 2015 of $315,401 and subtracting the over-recovery of projected costs for the period January through June 2015 of ($2,809,322), results in total program costs of $2,493,921 to be collected in this filing.

Mr. Sibo stated that in Cause No. 43618 DSM 8, NIPSCO transitioned from collecting EM&V costs on a "projected" basis, with appropriate reconciliation (as done in previous DSMA filings), to collecting EM&V costs on an "actual" basis. He explained that as part of the DSM 7 revenue reconciliation, NIPSCO adjusted the original revenue requirement to exclude the original projected costs for EM&V creating a reduction to the January through June 2016 revenue requirement and effectively crediting those projected costs back to the customers. Additionally, NIPSCO broke out the actual EM&V costs from the total program costs on Schedule 1.1 for clarity. Mr. Sibo sponsored Petitioner's Exhibit No. 1-A showing the revised DSM 7 revenue requirement.

Mr. Sibo testified regarding NIPSCO's request for continued authority to defer as a regulatory asset or regulatory liability the over- and under-recoveries of projected DSM program costs and lost margins incurred implementing the DSM programs prior to the time the Commission issues an order authorizing Petitioner to recognize these costs through the ratemaking process. He stated that NIPSCO will defer these costs on the balance sheet as a regulatory asset in Account 182.3 – Regulatory Asset or a regulatory liability in Account 254 – Other Regulatory Liabilities depending on the net balance of program costs.

8. <u>Calculation and Reconciliation of Lost Margins</u>. Petitioner's Exhibit No. 2-A, Revised Attachment A, Schedules 3.1, 3.2, 3.3, and 3.4 shows the energy and demand savings used in the calculation of lost margins and Schedule 3A provides a summary of the reconciliation of the previous reconciliation period. NIPSCO's request in this filing includes projected lost margins for the period January through December 2015 and includes the annual reconciliation of lost margins, which will be split between this Cause and NIPSCO's next DSM proceeding.

Ms. Vrab provided an explanation of the exhibits supporting Schedule 3. She stated that (1) Petitioner's Exhibit No. 2-D summarizes the actual EM&V related charges by month and by program that directly feed to Schedule 1, (2) Petitioner's Exhibit No. 2-E is the work product that feeds into Schedule 3 showing the detailed calculations supporting the energy and demand savings, (3) Petitioner's Exhibit No. 2-F showing the performance incentives that feeds into Schedule 1.2, and (4) Petitioner's Exhibit No. 2-G showing the update to program titles on the Schedules.

Ms. Vrab testified NIPSCO forecasted lost margins for measures to be installed in 2015 utilizing the deemed savings value provided by the net ex-post value from the most recent EM&V report as approved by the OSB. This is the same process NIPSCO used and uses for measures previously installed. If a measure is not included in the EM&V report approved by the OSB or the OSB has adopted a value different from that included in the EM&V report approved by the OSB, NIPSCO will forecast the lost margins utilizing the deemed savings value approved by the OSB.

According to Schedule 3A, the projected lost revenues for the period ending December 31, 2014 were $10,611,178 and after the reconciliation, the actual revenues for the period ending December 31, 2014 should have been $15,943,465 resulting in an under-collection of

$5,332,288. Taking the total demand recovery of $30,472 plus the energy recovery of $5,332,288, results in a total under-collection of $5,362,760. Ms. Vrab stated that because NIPSCO reconciles lost margins once per year and spreads that amount over twelve months, NIPSCO will collect half of that amount, or $2,681,379 from January 1 through June 30, 2016 and will collect the second half of that amount, or $2,681,379 from July 1 through December 31, 2016. Ms. Vrab explained that the under-collection of lost margins was due to the high activity seen at the end of Program Year 2 (i.e., 2013) for the Core programs in Energizing Indiana. She said there was a significant amount of savings accrued in 2014, resulting in a larger amount of savings achieved in 2014 than anticipated.

9. <u>Resulting DSMA Factors</u>. Mr. Sibo explained the calculation of NIPSCO's proposed DSMA factors. He sponsored Petitioner's Exhibit No. 2-A, Revised Attachment A, Schedules 2, 4, 5, 6 and 7 showing (1) projected program costs allocated to each rate schedule, (2) the allocation of lost margins based on energy and demand by rate schedule and by opt out period, (3) reconciliation of revenues by rate class, and (4) the calculation of DSMA factors by rate schedule. Mr. Sibo testified that consistent with the Order in DSM 7, NIPSCO allocated the projected program costs by program to the individual rate classes based on energy allocators for all costs incurred related to measures installed after December 31, 2014 and based on customer counts for all costs incurred related to measures installed up through December 31, 2014. NIPSCO allocated the projected lost margins by program to the individual rate classes based on energy allocators. He stated that the lost margin reconciliation amounts are included in this allocation. Once NIPSCO allocated the program costs and lost margins to the individual rate classes, and performed a reconciliation of revenue collection, NIPSCO then calculated the DSMA factors by dividing the cost per rate class by the respective forecasted usage. NIPSCO then adjusted the resulting DSMA factors to reflect Utility Receipts Tax on Retail Sales.

Petitioner's Revised Exhibit No. 1-C reflects the proposed DSMA factors for recovery in the period January through June 2016. This exhibit also shows the opt out program DSMA factors effective with the first billing cycle for the month of January 2016 for qualifying customers electing to opt out of participation in Petitioner's energy efficiency program and Rider 683 effective July 1, 2014 (i.e., Rate Class XXX.1), effective January 1, 2015 (i.e., Rate Class XXX.2), and effective January 1, 2016 (i.e., Rate Class XXX.3).

Petitioner's Revised Exhibit No. 1-D shows the estimated average monthly bill impact for a typical residential customer using (1) 688 kilowatt-hours ("kWh") per month is $1.20 (a $1.89 decrease in comparison to what a customer would pay today using the current DSMA factors) and (2) 1,000 kWh per month is $1.74 (a $2.75 decrease in comparison to what a customer would pay today using the current DSMA factors).

10. <u>Commission Findings</u>. The evidence presented in this Cause as discussed above supports approval of Petitioner's proposed revised DSMA factors as reasonable. Accordingly, we approve the requested DSMA factors. The resulting DSMA factors will be effective beginning the first billing cycle for the billing month of January 2016.

The Commission further finds that upon issuance of a final Order in Cause No. 44634, NIPSCO is directed to file revised schedules along with any additional supporting evidence in a subdocket to this Cause, i.e., Cause No. 43618 DSM 9 S 1, recalculating the factors to include any 2016 approved DSM program costs ("Phase 2 Schedules"). All parties will be permitted to review the Phase 2 Schedules and perform discovery. NIPSCO shall also confer with the OUCC and other interested parties and file an agreed proposed procedural schedule for the submission of comments and a hearing when it files its Phase 2 Schedules.

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

1. NIPSCO's request for approval of its revised DSMA factors is approved as set forth herein.

2. NIPSCO is granted continued authority to defer as a regulatory asset or regulatory liability the over- and under-recoveries of projected DSM program costs incurred implementing the DSM programs prior to the time the Commission issues an order authorizing Petitioner to recognize these costs through the ratemaking process.

3. NIPSCO shall file with the Energy Division of this Commission, prior to placing in effect the DSMA factors herein approved, a separate amendment to its rate schedules with a reasonable reference therein reflecting that such charge is applicable to all of its filed rate schedules, as shown in Petitioner's Revised Exhibit No.1-C.

4. A subdocket, Cause No. 43618 DSM 9 S 1, is created for the purpose of submission and review of NIPSCO's Phase 2 Schedules.

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

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

APPROVED: DEC 1 6 2015

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

Shala M. Coe

Shala M. Coe, Acting
Secretary to the Commission

ORIGINAL

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY FOR APPROVAL OF DEMAND SIDE MANAGEMENT ADJUSTMENT FACTORS FOR ELECTRIC SERVICE FOR THE BILLING CYCLES FOR THE MONTHS OF JULY THROUGH DECEMBER 2016 IN ACCORDANCE WITH THE ORDER OF THE COMMISSION IN CAUSE NOS. 44496 AND 44634.	)	**CAUSE NO. 43618 DSM 10** **APPROVED:** JUN 29 2016

ORDER OF THE COMMISSION

Presiding Officers:
James F. Huston, Commissioner
Loraine L. Seyfried, Chief Administrative Law Judge

On March 31, 2016, Northern Indiana Public Service Company ("NIPSCO" or "Petitioner") filed with the Indiana Utility Regulatory Commission ("Commission") its semi-annual request for approval of Demand Side Management Adjustment ("DSMA") Factors for electric service to be applicable for bills rendered during the billing cycles of July through December 2016. Also on March 31, 2016, Petitioner filed its case-in-chief, including direct testimony and exhibits supporting the proposed DSMA factors and the underlying costs for which Petitioner seeks cost recovery. On April 27, 2016, NIPSCO Industrial Group filed a petition to intervene, which was subsequently granted.[1] On May 12, 2016, the Indiana Office of Utility Consumer Counselor ("OUCC") filed its direct testimony and exhibits and the NIPSCO Industrial Group filed its Notice of Intent Not to File Testimony.

An evidentiary hearing was held on June 8, 2016, at 10:30 a.m. in Room 222 of the PNC Center, 101 West Washington Street, Indianapolis, Indiana. At the hearing, the prefiled evidence of NIPSCO and the OUCC was admitted into the record without objection and all parties waived cross-examination of witnesses. Also admitted into the record by stipulation of the parties was an exhibit of the NIPSCO Industrial Group containing certain discovery responses of Petitioner. No members of the general public appeared or participated at the hearing.

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

1. **Notice and Jurisdiction.** Notice of the 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. The Commission's May 25, 2011 Order in Cause No. 43618 authorized NIPSCO to seek recovery of costs associated with its Demand Side Management ("DSM") programs through a

[1] NIPSCO Industrial Group is comprised of Arcelor Mittal USA, Marathon Petroleum Company LP, Praxair, Inc., and United States Steel Corporation.

semi-annual adjustment mechanism. Under Ind. Code § 8-1-2-42, the Commission has jurisdiction over changes in Petitioner's schedules of rates and charges. Therefore, the Commission has jurisdiction over Petitioner and the subject matter of this Cause.

2. **Petitioner's Characteristics**. NIPSCO is a public utility organized and existing under the laws of the State of Indiana and having 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 used for the generation, transmission, distribution and furnishing of electric public utility service to the public within its assigned service territories.

3. **Background**. On November 12, 2014, the Commission issued an Order in Cause No. 44496 approving NIPSCO's electric DSM programs for the period January 2015 through December 2015 ("2015 Electric DSM Program") and granting NIPSCO authority through Rider 683 – Adjustment of Charges for Demand Side Management Adjustment Mechanism ("DSMA Mechanism") to: (1) recover start-up, implementation, and administrative costs along with the evaluation, measurement, and verification ("EM&V") costs of the DSM programs ("Program Costs") associated with the 2015 Electric DSM Program; and (2) recover lost revenues associated with the 2015 Electric DSM Program as well as lost revenues associated with previous program years. NIPSCO was also authorized to defer expenses and lost revenues associated with the 2015 Electric DSM Program and lost revenues for previous program years, including DSM programs previously offered but subsequently discontinued, until such amounts are recovered through rates.

On December 30, 2015, the Commission issued an Order in Cause No. 44634 ("44634 Order") approving NIPSCO's electric energy efficiency program effective for the period January 2016 through December 2018 ("2016-2018 EE Program").[2] The 44634 Order authorized NIPSCO to recover Program Costs and lost revenues associated with its 2016-2018 EE Program ("EE Program Costs") through the DSMA Mechanism. It also approved accounting and ratemaking treatment, including the authority to defer and recover: (1) the over- and under-recoveries of projected EE Program Costs through its DSMA Mechanism pending reconciliation in subsequent rider periods and approving the deferral of any costs incurred implementing the programs prior to the time the Commission issues an order authorizing NIPSCO to recognize those costs through the ratemaking process; and (2) lost revenues for previous program years, including DSM programs previously offered but subsequently discontinued, through the DSMA Mechanism until such amounts are recovered through rates.

4. **Requested Relief**. In this proceeding, Petitioner requests Commission approval of DSMA factors to be applicable for bills rendered during the billing cycles of July through December 2016. The factors proposed in this proceeding include estimated costs for the period July through December 2016 and reconcile the actual costs for the period July through December 2015. The proposed factors also include recovery of projected lost revenues for the period July through December 2016 and NIPSCO's last annual reconciliation of lost revenues for the period January through December 2014, half of which was recovered in Cause No. 43618 DSM 9 and

[2] Or until NIPSCO submits and receives approval of a plan under Ind. Code § 8-1-8.5-10, whichever occurs earlier.

the other half of which is included in this filing. NIPSCO's next annual reconciliation of lost revenues will occur in Cause No. 43618 DSM 11 for the period January through December 2015.

Petitioner also requests continued authority to defer as a regulatory asset or regulatory liability the over- and under-recoveries of projected EE Program Costs incurred implementing the DSM programs prior to the time the Commission issues an order authorizing Petitioner to recognize these costs through the ratemaking process. NIPSCO will defer these costs on the balance sheet as a regulatory asset in Account 182.3 – Regulatory Asset or a regulatory liability in Account 254 – Other Regulatory Liabilities depending on the net balance of EE Program Costs.

5. **Implementation of DSM Programs.** NIPSCO's witness Victoria A. Vrab, Director of Demand Side Management Programs, sponsored Attachment 2-B to Petitioner's Exhibit 2, which was the scorecard for NIPSCO's 2015 Electric DSM program and described the performance as follows:

- Residential Lighting Program – As of December 31, 2015, this program achieved 102% of its savings goal.

- Residential Home Energy Assessment & Weatherization Program – As of December 31, 2015, this program achieved 103% of its savings goal.

- Residential Income Qualified Weatherization Program – As of December 31, 2015, this program achieved 100% of its savings goal.

- Energy Efficiency Rebate Program – As of December 31, 2015, this program achieved 100% of its savings goal.

- School Education Program – As of December 31, 2015, this program achieved 101% of its savings goal.

- Residential New Construction Program – As of December 31, 2015, this program achieved 96% of its savings goal. The shortfall of electric savings was due to the unanticipated number of homes in the gas-only portion of NIPSCO's service territory.

- Residential Home Energy Conservation Program – As of December 31, 2015, this program achieved 121% of its savings goal.

- Commercial and Industrial ("C&I") Prescriptive Rebate Program – As of December 31, 2015, this program achieved 26% of its savings goal. Although performance at year end did not meet expectations, an overwhelming number of C&I applications were received within the last several weeks of the year that were not processed and paid in 2015 (but were subsequently processed and paid in 2016 and will be evaluated with other 2016 projects) and the program ultimately achieved approximately 81% of the savings goal.

- C&I Custom Program – NIPSCO uses a "pipeline" of anticipated savings to better align the program expectations because the timing for the completion of major projects is often difficult to accurately predict. As of December 31, 2015, this program achieved 55% of its savings goal. Performance at year end did not meet expectations, but because an overwhelming number of C&I applications were received within the last several weeks of the year that were not processed and paid in 2015 (but were subsequently processed and paid in 2016 and will be evaluated with other 2016 projects), the program ultimately achieved approximately 164% of the savings goal.

- C&I Small Business Direct Install Program – As of December 31, 2015, this program achieved 68% of its savings goal. Performance at year end did not meet expectations. However, because an overwhelming number of C&I applications were received within the last several weeks of the year that were not processed and paid in 2015 (but were subsequently processed and paid in 2016 and will be evaluated with other 2016 projects), the program ultimately achieved approximately 105% of the savings goal.

- School Audit and Direct Install Program – As of December 31, 2015, this program achieved 55% of its savings goal. Although performance at year end did not meet expectations, an overwhelming number of applications were received within the last several weeks of the year that were not processed and paid in 2015 (but were subsequently processed and paid in 2016 and will be evaluated with other 2016 projects) and the program ultimately achieved approximately 121% of the savings goal.

- A/C Cycling Program – As of December 31, 2015, this program achieved 94% of its kW savings goal. Four events were called which resulted in an average of 16,877 kW of savings.

NIPSCO witness Thomas S. Sibo, Manager, Regulatory Support and Analysis in the Rates and Regulatory Finance Department for NIPSCO, sponsored Attachment 1-E to Petitioner's Exhibit 1, which is a cost allocation matrix that shows: (1) the cost type (Program Costs, EM&V Costs, Lost Revenues) relating to Schedules 2.1, 2.2, 2.3, 2.4, 4.1A, 4.1, 4.2, 4.3, 4.4, 5.1A, 5.1, 5.2, 5.3, and 5.4; (2) the cost component (Forecast, Actual, Variance); (3) the period for each cost type; (4) the measures installed period; (5) and the parties who were allocated the costs (Opt-In Customers, Opt-Out 1 Customers, etc.).

6. Recovery and Reconciliation of Program Costs and Revenues. Ms. Vrab sponsored Attachment 2-A, Schedule 1 to Petitioner's Exhibit 2 showing a breakdown of projected and reconciled costs for the recovery period July through December 2016. The proposed DSMA factors reconcile Program Costs incurred for the period July through December 2015 and include projected costs for the period July through December 2016.

Ms. Vrab testified that for the period July through December 2016, NIPSCO projected annual costs based on actual program performance in 2015. For most of the C&I programs, there is a ramp-up period in the beginning of the year, which results in a projection of lower costs in the first half of the year, with the difference made up in the second half of the year. She stated that not taking this into account could result in large variances due to the lag in savings achievement for some programs. Therefore, based on actual 2015 program performance in the C&I programs, NIPSCO projected 83% of the costs will occur from July through December 2016. For the Residential programs, NIPSCO projected 50% of the costs will occur from July through December 2016. Lost revenues associated with measures to be installed in 2016 are projected at the same percentages as the Program Costs.

OUCC witness Thacker agreed with this methodology stating that it should help reduce the amount of variances in future periods by more closely matching the projected costs to the time period Petitioner expects them to be incurred.

Ms. Vrab testified the projected costs for the period July through December 2015 were \$8,889,289 and the actual costs incurred were \$12,952,826 resulting in an under-recovery of \$4,063,537. She stated that the main contributor to the under-recovery is the Residential Lighting Program and the C&I Custom Program.

As shown on Schedule 1, adding the \$10,355,056 of projected costs for the period July through December 2016 to the \$450,985 of actual EM&V costs for the period January 2014 through December 2015 and the \$4,063,537 under-recovery of projected costs for the period July through December 2015, results in total Program Costs of \$14,869,578 to be collected in this filing.

Mr. Sibo testified regarding NIPSCO's request for continued authority to defer as a regulatory asset or regulatory liability the over- and under-recoveries of projected EE Program Costs incurred implementing the DSM programs prior to the time the Commission issues an order authorizing Petitioner to recognize these costs through the ratemaking process. He stated that NIPSCO will defer these costs on the balance sheet as a regulatory asset in Account 182.3 – Regulatory Asset or a regulatory liability in Account 254 – Other Regulatory Liabilities depending on the net balance of EE Program Costs.

7. **Calculation and Reconciliation of Lost Revenues.** Ms. Vrab sponsored and provided an explanation of Petitioner's Exhibit 2, Attachment 2-A, Schedules 3.1, 3.2, 3.3, and 3.4 showing the energy and demand savings used in the calculation of lost revenues and Schedule 3A showing a summary of the reconciliation of the previous reconciliation period. NIPSCO's request in this filing includes projected lost revenues for the period July through December 2016 and includes the second half of the reconciliation of lost revenues approved in Cause No. 43618 DSM 9.

Ms. Vrab also sponsored Petitioner's Exhibit 2, Attachment 2-D, which summarizes the actual EM&V related charges by month and by program that directly feed to Schedule 1, and Attachment 2-E, which is the work product that feeds into Schedule 3 showing the detailed calculations supporting the energy and demand savings.

NIPSCO witness Alison M. Becker, Manager of Regulatory Policy, testified NIPSCO assumed the collection of lost revenues would continue to occur for the life of the measure for measures installed prior to January 1, 2016, as approved in Cause Nos. 44154 and 44496. As directed in the 44634 Order, for measures installed beginning January 1, 2016, NIPSCO limited lost revenue recovery to: (1) four years or the life of the measure, whichever is less, or (2) until rates are implemented pursuant to a final order in NIPSCO's next base rate case, whichever occurs earlier. She testified that when NIPSCO makes its compliance filing in Cause No. 44688 (NIPSCO's pending electric rate case) to remove the lost revenues associated with measures installed on or before December 31, 2014, the updated projected lost revenue will use the updated net energy rate factors approved in Cause No. 44688. The remainder of the methodology as discussed above will remain in place.

According to Petitioner's Exhibit 2, Attachment 2-A, Schedule 3A, the projected lost revenues for the period ending December 2014 were $10,611,178 and after the reconciliation the actual revenues for the period ending December 2014 should have been $15,943,465, resulting in an under-collection of $5,332,288. Taking the total Demand Recovery of $30,472 plus the Energy Recovery of $5,332,288, results in a total under-collection of $5,362,760. Ms. Vrab stated that because NIPSCO reconciles lost revenues once per year and spreads that amount over 12 months, NIPSCO collected half of that amount, or $2,681,380, from January through June 2016 and will collect the second half of that amount, or $2,681,380, from July through December 2016. Ms. Vrab explained the under-collection of lost revenues. She said that due to the high activity seen at the end of Program Year 2 (2013) for the Core programs in Energizing Indiana, there was a significant amount of savings that were accrued in 2014, resulting in a larger amount of savings achieved in 2014 than anticipated.

OUCC witness Thacker stated that NIPSCO filed lost revenues (both energy and demand) from all rate classes for the years 2010, 2011, and 2012. She stated that to the extent the Commission determines the cap created by the 44634 Order applies to those lost revenues, the OUCC has no objection to NIPSCO's calculations provided that amount is removed from the authorized recovery.

8. **Resulting DSMA Factors.** Mr. Sibo explained the calculation of NIPSCO's proposed DSMA factors. He sponsored Petitioner's Exhibit 2, Attachment 2-A, Schedules 2, 4, 5, 6, and 7 showing: (1) projected program costs allocated to each rate schedule; (2) the allocation of lost revenues based on energy and demand by rate schedule and by Opt-Out Period; (3) reconciliation of revenues by rate class; and (4) the calculation of DSMA factors by rate schedule. Mr. Sibo testified that consistent with the Order in Cause No. 43618 DSM 7, NIPSCO allocated the projected program costs by program to the individual rate classes based on energy allocators for all costs incurred related to measures installed after December 2014 and based on customer counts for all costs incurred related to measures installed up through December 2014. In addition, NIPSCO allocated the projected lost revenues by program to the individual rate classes based on energy allocators. He stated that the lost revenue reconciliation amounts are also included in this allocation. Once NIPSCO allocated the EE Program Costs to the individual rate classes and performed a reconciliation of revenue collection, NIPSCO calculated the DSMA factors by dividing the cost per rate class by the respective forecasted usage. NIPSCO then adjusted the resulting DSMA factors to reflect Utility Receipts Tax on Retail Sales.

Mr. Sibo sponsored Petitioner's Exhibit 1, Attachment 1-C reflecting the proposed DSMA factors for recovery in the period July through December 2016. This exhibit also shows the Opt-Out Program DSMA factors effective with the first billing cycle for the month of July

2016, in accordance with the provisions of Ind. Code § 8-1-8.5-9 and the June 30, 2014 Order in Cause No. 44441, for qualifying customers electing to opt-out of participation in Petitioner's energy efficiency program and the DSMA Mechanism effective July 1, 2014 (e.g., Rate Class XXX.1), effective January 1, 2015 (e.g., Rate Class XXX.2) and effective January 1, 2016 (e.g., Rate Class XXX.3).

Mr. Sibo sponsored Petitioner's Exhibit 1, Attachment 1-D showing the estimated average monthly bill impact for a typical residential customer using: (1) 688 kilowatt-hours ("kWh") per month is $3.31 (a $0.66 increase in comparison to what a customer would pay today using the current DSMA factors); and (2) 1,000 kWh per month is $4.82 (a $0.97 increase in comparison to what a customer would pay today using the current DSMA factors). Ms. Thacker confirmed the accuracy of NIPSCO's calculation of its residential DSMA Factor.

9. **Commission Findings.** The evidence presented in this Cause as discussed above supports approval of Petitioner's proposed DSMA factors as reasonable. Accordingly, we approve the requested DSMA factors. The resulting DSMA factors will be effective for the first billing cycle for the month of July 2016. We also find NIPSCO's request for continued authority to defer over- and under-recoveries to be reasonable and accordingly we approve that request. However, when the Commission issues its Order in NIPSCO's pending base rate case, Cause No. 44688, NIPSCO shall make a compliance filing in this Cause to remove the lost revenues associated with any DSM measures installed on or before December 31, 2014.

In addition, there appears to be some confusion with respect to NIPSCO's authorized lost revenue recovery as a result of the 44634 Order, which approved NIPSCO's 2016-2018 EE Program. In that Order, we limited lost revenue recovery for the 2016-2018 EE Program based on the evidence presented by the parties. However, we did not alter the lost revenue recovery for DSM measures that were approved by other Commission Orders and installed prior to January 1, 2016, despite the parties' arguments that we should do so because not all lost revenues would be zeroed out in NIPSCO's base rate case. Having already considered the matter and without any new evidence to be considered, we decline to otherwise alter the recovery of lost revenues incurred for the 2015 DSM measures.[3]

Finally, although NIPSCO currently provides a scorecard with its DSM filings, we find that beginning with its next DSM filing, NIPSCO's scorecard should include for each program: gross MWh savings at the meter and gross MW savings at the meter. The savings to be reported are to include: ex ante savings, audited savings, and verified savings as these numbers become available.[4] The scorecard should also include budgeted and actual program expenditures excluding lost revenues and performance incentives. Future scorecards should be submitted on a quarterly basis with the fourth quarter scorecard also including the information for the full year.

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[3] As indicated above, with the issuance of the Commission's Order in Cause No. 44688, NIPSCO will no longer recover any lost revenues associated with DSM measures installed prior to 2015.

[4] Ex-ante savings are those energy savings from program tracking system as reported by the third-party administrator or the utility; audited savings are the ex-ante savings after deemed calculations and project/measure counts have been confirmed by the evaluation administrator; verified savings are the savings estimated following confirmation of the installation and use of a sample of project/measure installations.

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

1. NIPSCO's requested DSMA factors are approved.

2. NIPSCO is granted continued authority to defer as a regulatory asset or regulatory liability the over- and under-recoveries of projected EE Program Costs incurred implementing the DSM programs prior to the time the Commission issues an order authorizing Petitioner to recognize these costs through the ratemaking process.

3. Prior to placing the approved DSMA factors in effect, NIPSCO shall file with the Commission's Energy Division a separate amendment to its rate schedules with a reasonable reference therein reflecting that such charge is applicable to all of its filed rate schedule, as shown in Petitioner's Exhibit 1, Attachment 1-C.

4. Upon issuance of the Commission's Order in Cause No. 44688, NIPSCO shall file a compliance filing under this Cause removing the lost revenues associated with any DSM measures installed on or before December 31, 2014. Such compliance filing shall be made so that the revised DSMA factors will take effect with the effective date of the new base rates.

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

STEPHAN, HUSTON, WEBER, AND ZIEGNER CONCUR:

APPROVED: JUN 29 2016

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

Mary M. Becerra

Mary M. Becerra
Secretary of the Commission

ORIGINAL

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY FOR APPROVAL OF (1) DEMAND SIDE MANAGEMENT ADJUSTMENT FACTORS FOR ELECTRIC SERVICE FOR THE BILLING CYCLES FOR THE MONTHS OF MARCH THROUGH DECEMBER, 2017 IN ACCORDANCE WITH THE ORDER OF THE COMMISSION IN CAUSE NO. 44496 AND 44634 AND (2) MODIFICATION OF RIDER 783 – DEMAND SIDE MANAGEMENT ADJUSTMENT MECHANISM AND APPENDIX G – DEMAND SIDE MANAGEMENT ADJUSTMENT MECHANISM FACTOR.	)	CAUSE NO. 43618 DSM 11 APPROVED: FEB 2 2 2017

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ORDER OF THE COMMISSION

Presiding Officers:
James F. Huston, Commissioner
Jefferson S. Garn, Administrative Law Judge

On December 1, 2016, Northern Indiana Public Service Company ("NIPSCO" or "Petitioner") filed its request for Indiana Utility Regulatory Commission ("Commission") approval of Demand Side Management Adjustment ("DSMA") Factors for electric service for the billing cycles for the months of March through December 2017. Petitioner on that date also filed its case-in-chief, including direct testimony and attachments supporting the proposed Demand Side Management Adjustment Mechanism ("DSMA") Factors and the underlying costs for which Petitioner seeks recovery. NIPSCO filed a Submission of Revised Schedule 1 on December 22, 2016. On January 12, 2017, the Indiana Office of Utility Consumer Counselor ("OUCC") prefiled the testimony and exhibits of Crystal L. Thacker.

An evidentiary hearing was held on February 6, 2017 at 1:30 p.m. in Room 224 of the PNC Center, 101 West Washington Street, Indianapolis, Indiana. At the hearing, the prefiled evidence of NIPSCO and the OUCC was admitted into the record without objection and both parties waived cross-examination of witnesses. No members of the general public appeared or participated at the hearing.

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

1. **Notice and Jurisdiction.** The Commission gave and published the legally required notice of the hearing in this Cause. NIPSCO is a public utility as that term is defined in Ind. Code § 8-1-2-1. The Commission's May 25, 2011 Order in Cause No. 43618 authorized NIPSCO to seek recovery of costs associated with its Demand Side Management ("DSM") program through a semi-annual adjustment mechanism. Under Ind. Code § 8-1-2-42, the Commission has jurisdiction over changes in Petitioner's schedules of rates and charges. Therefore, the Commission has jurisdiction over Petitioner and the subject matter of this Cause.

2. **Petitioner's Characteristics.** Petitioner is a public utility organized and existing under State of Indiana law, with its principal office at 801 East 86th Avenue, Merrillville, Indiana. Petitioner renders electric public utility service in Indiana and owns, operates, manages, and controls, among other things, plant and equipment used for the generation, transmission, distribution, and furnishing of electric public utility service to the public within its assigned service territories.

3. **Background.** On November 12, 2014, the Commission issued an Order in Cause No. 44496 ("44496 Order") approving NIPSCO's DSM programs for January 2015 through December 2015 (the "2015 Electric DSM Program"). That order also granted NIPSCO authority through Rider 683 – Adjustment of Charges for Demand Side Management Adjustment Mechanism ("DSMA Mechanism") to recover associated start-up, implementation, and administrative costs, along with costs associated with the evaluation, measurement, and verification ("EM&V") of those programs associated with the 2015 Electric DSM Program. NIPSCO could also recover lost revenues associated with previous program years. The Commission also authorized NIPSCO to defer expenses and lost revenues associated with the 2015 Electric DSM Program and lost revenues for previous program years, including DSM programs subsequently discontinued, until they can be recovered through rates.

On December 30, 2015, the Commission issued an Order in Cause No. 44634 ("44634 Order") approving NIPSCO's electric energy efficiency program effective for January 2016 through December 2018 ("2016-2018 EE Program").[1] The Commission also authorized NIPSCO to recover energy efficiency ("EE") program costs and lost revenues ("Program Costs") through the DSMA Mechanism. It also approved accounting and ratemaking treatment, including the authority to defer and recover: (1) the over- and under-recoveries of projected EE Program Costs through its DSMA Mechanism, pending reconciliation in subsequent rider periods, and approving the deferral of any costs incurred implementing the programs before the Commission issues an order authorizing NIPSCO to recognize those costs through the ratemaking process; and (2) lost revenues for previous program years, including DSM programs subsequently discontinued.

The Commission's July 18, 2016 Order in Cause No. 44688 (the "44688 Order") approved NIPSCO's Rider 783 – Demand Side Management Adjustment Mechanism and Appendix G – Demand Side Management Adjustment Mechanism (DSMA) Factor, to become effective October 1, 2016. The Commission approved NIPSCO's proposal to reset lost revenues in its DSMA Mechanism, effective upon the implementation of new base rates (October, 2016), to eliminate lost revenues attributable to all energy efficiency measures installed on or before December 31, 2014.

4. **Requested Relief.** Petitioner now requests Commission approval of DSMA Factors to be effective for the billing cycles for the months of March through December 2017. The factors proposed in this proceeding include estimated costs for the period January through December 2017 and the reconciliation of actual costs for January through June 2016. This filing also includes NIPSCO's annual reconciliation of lost revenues for January through December 2015.

Petitioner proposes modifications to its DSMA Rider and Appendix G – Demand Side Management Adjustment Factor to reflect NIPSCO's proposed transition from semi-annual to annual DSMA filings, and a change to the date by which eligible customers must notify NIPSCO of their

[1] Or until NIPSCO submits and receives approval of a plan under Ind. Code § 8-1-8.5-10, whichever occurs earlier.

intent to opt out of or opt in to NIPSCO's Electric DSM Program.

Petitioner also requests continued authority to defer as a regulatory asset or regulatory liability the over- and under-recoveries of projected EE Program Costs incurred implementing the DSM programs until the Commission issues an order authorizing Petitioner to recover these costs through the ratemaking process. NIPSCO will defer these costs on the balance sheet as a regulatory asset in Account 182.3 – Regulatory Asset or a regulatory liability in Account 254 – Other Regulatory Liabilities, depending on the net balance of EE Program Costs.

5. Annual DSMA Filing, Modifications to Tariff, Modification to Opt-In / Opt Out Process, and Compliance Filing for Lost Revenues True-Up. NIPSCO witness Alison M. Becker, Manager of Regulatory Policy, supported NIPSCO's proposal to change from a semi-annual to annual DSMA tracker filing, described NIPSCO's proposed modifications to Rider 783 –Demand Side Management Adjustment Mechanism and opt out / opt in process for qualified customers, and discussed NIPSCO's proposed treatment of customers who opted out on or before January 1, 2015.

Ms. Becker testified that, rather than filing in September (with a January 1 effective date) and March (with a July 1 effective date), NIPSCO proposes to file by July 15 (with a January 1 effective date) for a 12-month period of the DSMA Mechanism. She stated that, if approved, NIPSCO's first annual filing will be made no later than July 15, 2017, and NIPSCO will request factors to be applicable for the period January through December 2018, or until replaced by different factors approved in a subsequent filing. NIPSCO would adjust annually the DSM Factors and include a reconciliation of the previous estimated DSM Factors with actual costs and estimate new DSM Factors for the upcoming 12 months.

Ms. Becker explained that NIPSCO believes the changed filing schedule is appropriate because it promotes administrative efficiency, reducing the administrative burden on the Commission, the OUCC, and any other parties. Another benefit is that filing by July 15, with a factor going into effect January 1, will allow for a longer procedural schedule and more time for the Commission and other parties to consider NIPSCO's filing. In addition, DSMs traditionally function with slower spending at the beginning of the year and more spending toward the latter half of the year. Consequently, an annual tracker should balance out some of the unevenness associated with the program expenditures.

Ms. Becker suggested that any difficulties associated with an annual filing are mitigated by mechanisms in place that permit parties to continue to share information outside of a tracker proceeding. She explained that the OUCC and other parties who typically intervene in NIPSCO's DSM tracker proceedings are part of NIPSCO's Oversight Board ("OSB"). The OSB meets approximately monthly and has on-going conversations throughout the month. If parties want to see additional information that is typically provided in a tracker proceeding, but not typically shared as part of those monthly meetings, NIPSCO would be open to discussing how best to facilitate those requests. But NIPSCO hopes that the monthly performance updates as well as information from the vendor will provide sufficient detail for the OSB throughout the year. Ms. Becker testified that a change to annual filing would not require any changes to the reporting requirements associated with NIPSCO's 2016-2018 EE Program.

OUCC witness Crystal L. Thacker, Utility Analyst in the OUCC's Electric Division, stated the OUCC does not oppose NIPSCO's proposal to change the DSM proceeding from a semi-annual to an annual filing.

Ms. Becker described NIPSCO's proposed changes to its DSMA Mechanism. She explained that to facilitate an annual filing, NIPSCO proposes changing the notification date for customers to opt out or opt in to NIPSCO's DSM programs from November 15 to May 15 (with an effective date of January 1 of the following year), permitting those customers to be included in NIPSCO's initial July 1 annual filing. Without this change, NIPSCO would need to make a compliance filing after the record had closed (and potentially after an Order had been issued approving NIPSCO's factors). Having the actual opt out/in numbers before the initial annual filing will allow NIPSCO to include the final numbers and would allow the other parties to know what the actual factors are, eliminating the need for a compliance filing.

Ms. Becker sponsored Attachment 3-A, reflecting changes to the DSMA Mechanism. First, NIPSCO proposes to update the date by which a customer must notify NIPSCO of its intention to opt out of/back in to NIPSCO's DSM programs. Second, a reference to collecting lost revenues over two six-month DSMA Factor periods would be updated to reflect a single annual period. In addition, there is one formatting change and there are references to "Rider 683" instead of "Rider 783," a typographical error from an earlier version.

Ms. Becker testified that, at the conclusion of NIPSCO's last base rate case (Cause No. 44688), the lost revenues for measures installed through December 31, 2014, were "reset" because they were included in base rates. Therefore, customers who opted out of participating in NIPSCO's DSM program effective on or before January 1, 2015, (Opt Out 1 and Opt Out 2) would no longer have any costs associated with the DSM program. But there are still volumetric true ups from those lost revenues, meaning the customers should still have a charge. She stated that, rather than continue to have a relatively small charge on the customers' bills for the volumetric true up, NIPSCO proposes a one-time true up after the final results are in for 2017. Ms. Becker stated that many of NIPSCO's customers who opted out did so with the intention of knowing the DSM charge would no longer be on the bill and could be an item removed from the budgeting process. Continuing to have a charge or credit, no matter how small, does not meet that objective. By having the one-time true up, the customer has an electric bill without the DSM charge on it and NIPSCO is unharmed in the process.

NIPSCO witness Derric J. Isensee, Executive Director of Rates and Regulatory Finance, sponsored Attachment 1-D reflecting the changes to Appendix G – Demand Side Management Adjustment Mechanism (DSMA) Factor. He testified about the Schedule 1 and Schedule 3 updates that include an annual level of Program Costs and lost revenues to accommodate the proposed change in the frequency of its tracker filings from a semi-annual to annual basis, and the update of billing determinants calculated in Schedule 7. In addition to these changes, all schedules have been updated to reflect customers who have chosen to opt-out beginning January 1, 2017 (reflected as Rate Schedule "7XX.4"). Finally, Schedule 7 has been updated to break out the lost revenue reconciliation independent from the forecasted lost revenues, reflected in the added Columns (h) and (l) to show the energy and demand lost revenue variances.

Mr. Isensee explained that, to transition to an annual filing, in this filing NIPSCO has forecasted the collection of Program Costs for the period January through December 2017, rather than the typical January through June 2017 time period. In order to capture the impact of 2017 opt-out customers, which took place in November 2016, NIPSCO opted to file this tracker on December 1, 2016. NIPSCO proposes to file going forward its annual tracker filing by July 15 of each year for a 12-month period.

Mr. Isensee testified that, in this filing, NIPSCO has added Schedule 8 showing a preliminary calculation of all Pre-2015 Remaining Costs. The final reconciliation could not be quantified because the affected customers (7XX.1 and 7XX.2) are currently paying the DSM-10 DSM Factors and will continue to pay those DSM Factors until replaced by new factors in this filing. Therefore, NIPSCO proposes making a compliance filing in this Cause in April 2017 or 30 days after a final order is issued in this Cause, whichever occurs later, to finalize the calculation of the Pre-2015 Remaining Costs and associated one-time, final, fixed charge.

OUCC witness Ms. Thacker stated NIPSCO's proposed calculation of the final charge (credit) should allow the Opt Out 1 and Opt Out 2 customers to be completely eliminated from future DSM filings without adversely effecting other customer classes, but reserved the right to review the compliance filing and issue discovery, as needed.

6. Implementation of DSM Programs. NIPSCO witness Victoria A. Vrab, Director of Demand Side Management Programs, described its change in the vendor that provides NIPSCO's EE services in 2017. NIPSCO, after consultation with its OSB, elected to transition the Residential portfolio to Lockheed Martin to better meet the needs of NIPSCO's residential customers. She explained that NIPSCO made this decision because Lockheed Martin can effectively manage a complete energy efficiency portfolio and attain economies of scale associated with its commercial and industrial ("C&I") program implementation, including shared resource/infrastructure, shared branding/general awareness marketing, cross promotion of both program portfolios, and trade ally portfolio overlap. NIPSCO will review the vendor or vendors' performance before extending any contract in 2018.

Ms. Vrab explained the role NIPSCO's OSB plays in program design and budget modifications. The Commission established NIPSCO's OSB through its July 27, 2011 Order in Cause No. 43912. NIPSCO continues to strengthen its relationship with its OSB and works with OSB members on program designs for its 2016-2018 EE Program. NIPSCO's OSB provides general recommendations throughout the year and approves program designs and budgets as provided within Commission approval and the OSB governance document. Over the course of the program year, the OSB monitors the programs and provides oversight of and approval for programmatic changes.

Ms. Vrab sponsored Attachment 2-B, NIPSCO's scorecard for NIPSCO's 2016-2018 EE Program for the period January through September 2016. The scorecard complies with the Commission's June 29, 2016 Order in Cause No. 43618 DSM 10 by including program descriptions and performance updates as well as gross MWh and MW savings at the meter for each program and includes budgeted and actual program expenditures excluding lost revenues and EM&V expenditures. The attachment described the performance as of September 30, 2016, as follows:

- *Residential Heating, Ventilation and Air Conditioning Rebate Program* – This program achieved 55% of its savings goal.

- *Residential Lighting Program* – This program achieved 82% of its savings goal and is on track to meet its annual savings goal.

- *Residential Home Energy Assessment Program* – This program achieved 18% of its savings goal. This program has not traditionally performed well within NIPSCO's service territory, and NIPSCO is scaling it back for 2017.

- *Residential Appliance Recycling Program* – This program achieved 42% of its savings goal. NIPSCO does not expect that this program will meet its annual savings goal by year-end because of the program's slow start.

- *Residential Low Income Appliance Replacement* – This program achieved 14% of its savings goal. NIPSCO does not expect that this program will meet its annual savings goal by year-end because of this program's slow start. NIPSCO elected to move the refrigerator replacement measure to the Residential Income Qualified Weatherization ("IQW") program in 2017, in the hope of streamlining providing refrigerators and increasing the number of customers receiving energy efficient appliances.

- *Residential School Education Program* – This program achieved 81% of its savings goal and is expected to meet 100% by year-end. This program continues to be well received within NIPSCO's service territory.

- *Residential Behavioral Program* – This program achieved 8% of its savings goal. NIPSCO has chosen to return to a more traditional program in 2017 through the distribution of paper and email reports because of the delayed start of this program and other issues that continued through the implementation of this program.

- *Residential IQW Program* – This program achieved 54% of its revised savings goal. NIPSCO worked with its OSB to increase this program's budget and savings goal to support the customers' participation in this program through year-end. Without the revision, the program would have surpassed its budget and goal by September 30.

- *C&I Prescriptive Program* – This program achieved 30% of its savings goal. Lockheed Martin has a "pipeline" of expected savings (8,758,866 kWh) to better align the program expectations. These expected savings are based on those applications that require preapproval due to the larger incentive amount and are in addition to the savings already achieved.

- *C&I Custom Program* – This program achieved 9% of its savings goal. As with most custom projects, the timing for the completion of such major projects is often difficult to accurately predict. But Lockheed Martin has a "pipeline" of expected savings (16,827,951 kWh) to better align the program expectations, and the pipeline savings are in addition to the savings already achieved.

- *C&I New Construction Program* – This program achieved 22% of its savings goal. The market has not been as receptive to the program as Lockheed Martin initially expected. Lockheed Martin continues to look for ways to increase participation. Lockheed Martin uses a "pipeline" of anticipated savings (2,035,070 kWh) to better align the program expectations, and the pipeline savings are in addition to the savings already achieved.

- *C&I Small Business Direct Install ("SBDI") Program* –This program achieved 68% of its savings goal. This program continues to succeed due to the change in measures being offered, from previous program years, which better align with the customers' needs. Lockheed Martin uses a "pipeline" of expected savings (2,730,303 kWh) to better align the program expectations, and the pipeline savings are in addition to the savings already achieved. This program was expected to perform well for the remainder of 2016 as well as in 2017.

- *C&I Retro-Commissioning Program* – This program achieved 0% of its savings goal. There are no projects currently in the pipeline, although Lockheed Martin still considers this program to have potential within NIPSCO's service territory.

Mr. Isensee sponsored Attachment 1-C, which is a cost allocation matrix that shows (1) the cost type (Program Costs, EM&V Costs, Lost Revenues) relating to Schedules 2.1, 2.2, 2.3, 2.4, 2.5, 4.1A, 4.1, 4.2, 4.3, 4.4, 5.1A, 5.1, 5.2, 5.3, and 5.4, (2) the cost component (Forecast, Actual, Variance), (3) the period for each cost type; (4) the measures-installed period; and (5) the parties who were allocated the costs (Opt-In Customers, Opt-Out 1 Customers, etc.).

7. **<u>Recovery and Reconciliation of Program Costs and Revenues</u>.** Ms. Vrab sponsored Attachment 2-A, Schedule 1, which details the projected and reconciled costs for the recovery period, January through June 2016. This filing reconciles Program Costs incurred for January through June 2016 and includes projected costs for January through December 2017.

Ms. Vrab explained the exhibit supporting Schedule 1. Attachment 2-C is the work product that feeds into Schedule 1 showing the actual costs incurred from January through June 2016 and the projected costs for the period January through December 2017.

Ms. Vrab testified that Residential projections were based on the approved program savings and budget amounts because NIPSCO is transitioning to a different Residential vendor for 2017. C&I projections were based on a forecast provided by Lockheed Martin which was informed by 2016 activity.

Ms. Vrab also testified the projected costs for January through June 2016 were $3,973,531 and the actual costs incurred were $5,884,447, resulting in an under-recovery of $1,910,915. The Residential School Education Program, the C&I SBDI Program, and the C&I Prescriptive Program were the main contributors to the under-recovery.

As shown on Attachment 2-A, Revised Schedule 1, adding $13,992,464, the projected costs for January through December 2017, to $671,082, the actual EM&V costs for January 2014 through December 2015, and then to $1,910,915, the under-recovery of projected costs for January through June 2016, results in $16,574,461, the total Program Costs to be collected in this filing.

Mr. Isensee testified about NIPSCO's request for continued authority to defer as a regulatory asset or regulatory liability the over- and under- recoveries of projected Program Costs and Program Costs incurred implementing the 2016-2018 EE Program until the Commission issues an order authorizing Petitioner to recognize these costs through the ratemaking process. NIPSCO will defer these costs on the balance sheet as a regulatory asset or a regulatory liability, depending on the net balance of Program Costs.

8. <u>Calculation and Reconciliation of Lost Margins</u>. Ms. Vrab sponsored Attachment 2-A, Schedules 3.1, 3.2 and 3.3, which show the energy and demand savings used in the calculation of lost revenues, and Schedule 3A, which shows a summary of the reconciliation of the previous reconciliation period. NIPSCO's request in this filing includes projected lost revenues for January through December 2017 and NIPSCO's annual reconciliation of lost revenues for January through December 2015, all intended to be recovered through this proceeding.

Ms. Vrab explained the exhibits supporting Schedule 3. Attachment 2-D summarizes the actual EM&V related charges that directly feed to Schedule 1. Attachment 2-E is the work product that feeds into Schedule 3 and shows the detailed calculations supporting the energy and demand savings. Attachment 2-F shows the update to program titles on the Schedules.

According to Schedule 3A, the projected lost revenues for January through December 2015 were $19,274,281 and, after the reconciliation, the actual revenues for January through December 2015 should have been $19,734,059, resulting in an under-collection of $459,778. The total Demand over-recovery of $637,763, in conjunction with the Energy under-recovery of $459,778, results in a total over-collection of $177,985. There were variances throughout energy and demand across all programs. The main contributor to this over-collection of lost revenues was influenced by the results of two EM&V reports and the cumulative nature of the savings. Specifically, the energy variances were the result of an under-collection with the C&I Prescriptive Program, which was attributed to the Energizing Indiana's double incentive promotion that was offered at the end of Program Year 2 (2013) and accrued in 2014, and the result of the over-collection was attributed to the lower than expected program performance with the C&I Custom Program, Residential Multi-Family Direct Install Program, and Residential Home Energy Audit Program.

9. <u>Resulting DSMA Factors</u>. Mr. Isensee explained NIPSCO's proposed DSMA Factors calculation. He averred that the proposed ratemaking treatment is consistent with the 44496 Order and 44634 Order. He sponsored Attachment 2-A, Schedules 2, 4, 5, 6 and 7, which show (1) projected Program Costs allocated to each rate schedule, (2) the allocation of lost revenues based on energy and demand by rate schedule and by Opt-Out Period, (3) reconciliation of revenues by rate class, and (4) the calculation of DSMA factors by rate schedule.

Mr. Isensee testified that the DSMA Factors are developed with forecasted Program Costs and lost revenues (with the exception of EM&V costs which are recovered based on actual costs). The projected Program Costs are reconciled to actual Program Costs in a subsequent filing. As shown in Schedule 2, NIPSCO then allocates the projected Program Costs by program to the individual rate classes based on energy allocators, consistent with the Commission's December 30, 2014 Order in Cause No. 43618 DSM 7 ("DSM-7 Order"). As shown in Schedules 4 and 5, NIPSCO allocates the projected lost revenues by program to the individual rate classes based on energy allocators consistent with the DSM-7 Order. This filing also includes NIPSCO's reconciliation of forecasted lost revenues. Once NIPSCO allocates the Program Costs to the individual rate classes and performs a reconciliation of revenue collection, NIPSCO then calculates the DSMA Factors by dividing the cost per rate class by the respective forecasted usage. NIPSCO then adjusts the resulting DSMA Factors to reflect Utility Receipts Tax on Retail Sales.

Mr. Isensee sponsored Attachment 1-D, reflecting the proposed modification and DSMA Factors for recovery from March through December 2017.

He also sponsored Attachment 1-E, showing the calculation of the estimated average monthly bill impact for a typical residential customer using (1) 698 kilowatt-hours ("kWh") per month is $2.63 (a $0.43 increase in comparison to what a customer would pay today using the current DSMA Factors) and (2) 1,000 kWh per month is $3.77 (a $0.61 increase in comparison to what a customer would pay today using the current DSMA Factors). Ms. Thacker confirmed the accuracy of NIPSCO's calculation of its residential DSMA factor.

10. <u>Commission Findings</u>. Based on the evidence presented, we find NIPSCO's proposal to change the timing of future DSM tracker filings, from semi-annual filings to an annual filing, is reasonable, appropriate, consistent with administrative efficiency, and should be approved. We also find NIPSCO's proposed modifications to Rider 783 – Demand Side Management Adjustment Mechanism and Appendix G – Demand Side Management Adjustment Mechanism Factor, to reflect NIPSCO's proposed transition from semi-annual to annual DSM filings, as well as other unrelated minor wording changes, are reasonable, appropriate, and should be approved.

With regard to the final costs associated with the DSM program to customers who opted out of participating in NIPSCO's DSM program effective on or before January 1, 2015 (Opt Out 1 and Opt Out 2), we find that NIPSCO's proposal to make a compliance filing in this Cause to implement a one-time true up after a final reconciliation of volumetric true ups of lost revenues can be determined, is reasonable, appropriate, and should be approved, but recognize the OUCC's reserved right to review any compliance filing and issue discovery as needed.

We further find NIPSCO's proposed DSMA Factors are reasonable and properly calculated; therefore, we approve the DSMA Factors contained in Schedule 7 to be effective for the first billing cycle for the billing month of March 2017, to remain in effect through December 2017, or until replaced by different adjustment factors approved in subsequent filing. We also find NIPSCO's request for continued authority to defer over- and under-recoveries of projected Program Costs and Program Costs incurred implementing DSM programs until the Commission issues an order authorizing Petitioner to recognize these costs through the ratemaking process to be reasonable, and accordingly we approve that request.

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

1. NIPSCO's proposed modifications to Rider 783 – Demand Side Management Adjustment Mechanism and Appendix G – Demand Side Management Adjustment Mechanism (DSMA) Factor to change the frequency of its tracker filings from semi-annual to annual are approved to be applicable with its DSM-12 filing, to be made no later than July 15, 2017.

2. NIPSCO's request for approval of its revised DSMA Factors as set out in Schedule 7 (with estimated impact set forth in Petitioner's Attachment 1-E) is approved.

3. NIPSCO is granted continued authority to defer as a regulatory asset or regulatory liability the over and under recoveries of projected Program Costs and Program Costs incurred implementing the DSM programs until the Commission issues an order authorizing Petitioner to recognize these costs through the ratemaking process.

4. Before implementing the rates authorized by this Order, NIPSCO shall file with the Commission's Energy Division an amendment to its rate schedules (shown in Attachment 3-A and Attachment 1-D).

5. NIPSCO shall make a compliance filing no later than April 30, 2017, to finalize the calculation of the Pre-2015 Remaining Costs and associated one-time, final, fixed charge.

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

ATTERHOLT, FREEMAN, HUSTON, WEBER, AND ZIEGNER CONCUR:

APPROVED: FEB 22 2017

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

Mary M. Becerra

Mary M. Becerra
Secretary to the Commission

ORIGINAL

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY FOR APPROVAL OF DEMAND SIDE MANAGEMENT ADJUSTMENT FACTORS FOR ELECTRIC SERVICE FOR THE BILLING CYCLES FOR THE MONTHS OF JANUARY THROUGH DECEMBER, 2018 AND CONTINUED ACCOUNTING AUTHORITY IN ACCORDANCE WITH THE ORDER OF THE COMMISSION IN CAUSE NO. 44634.	CAUSE NO. 43618 DSM 12 APPROVED: DEC 13 2017

ORDER OF THE COMMISSION

Sarah E. Freeman, Commissioner
Marya E. Jones, Administrative Law Judge

On July 14, 2017, Northern Indiana Public Service Company ("NIPSCO" or "Petitioner") filed its request for Indiana Utility Regulatory Commission ("Commission") approval of Demand Side Management Adjustment ("DSMA") Factors for electric service for the billing cycles for the months of January through December 2018. On the same date Petitioner also filed its case-in-chief, including direct testimony and attachments supporting the proposed DSMA Factors and the underlying costs for which Petitioner seeks recovery. On September 27, 2017, the Indiana Office of Utility Consumer Counselor ("OUCC") prefiled the testimony and exhibits of Crystal L. Barrett.

An evidentiary hearing was held on November 2, 2017 at 10:00 a.m. in Room 224 of the PNC Center, 101 West Washington Street, Indianapolis, Indiana. At the hearing, the prefiled evidence of NIPSCO and the OUCC was admitted into the record without objection and both parties waived cross-examination of witnesses.

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

1. **Notice and Jurisdiction.** Notice of the 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. The Commission's May 25, 2011 Order in Cause No. 43618 authorized NIPSCO to seek recovery of costs associated with its Demand Side Management ("DSM") program through a semi-annual adjustment mechanism. The Commission's February 22, 2017, Order in Cause No. 43618 DSM 11 ("DSM 11 Order") authorized NIPSCO to change the timing of future DSM tracker filings from semi-annual filings to an annual filing. Under Ind. Code § 8-1-2-42, the Commission has jurisdiction over changes in Petitioner's schedules of rates and charges.

Therefore, the Commission has jurisdiction over Petitioner and the subject matter of this Cause.

2. **Petitioner's Characteristics.** Petitioner is a public utility organized and existing under the laws of the State of Indiana and having its principal office at 801 East 86th Avenue, Merrillville, Indiana. Petitioner renders electric public utility service in the State of Indiana and owns, operates, manages, and controls, among other things, plant and equipment within the State used for the generation, transmission, distribution, and furnishing of electric public utility service to the public within its assigned service territories.

3. **Background.** On November 12, 2014, the Commission issued an Order in Cause No. 44496 approving NIPSCO's DSM programs for January 2015 through December 2015 (the "2015 Electric DSM Program"). That order also granted NIPSCO authority through Rider 683 – Adjustment of Charges for Demand Side Management Adjustment Mechanism ("DSMA Mechanism") to recover associated start-up, implementation, and administrative costs, along with costs associated with the evaluation, measurement, and verification ("EM&V") of those programs associated with the 2015 Electric DSM Program. NIPSCO could also recover lost revenues associated with previous program years. The Commission also authorized NIPSCO to defer expenses and lost revenues associated with the 2015 Electric DSM Program and lost revenues for previous program years, including DSM programs subsequently discontinued, until they can be recovered through rates.

On December 30, 2015, the Commission issued an Order in Cause No. 44634 ("44634 Order") approving NIPSCO's electric energy efficiency program effective for the period January 1, 2016 through December 31, 2018[1] ("2016-2018 EE Program"). The Commission also authorized NIPSCO to recover energy efficiency ("EE") program costs and lost revenues ("Program Costs") through the DSMA Mechanism. Additionally, the Commission approved accounting and ratemaking treatment, including the authority to defer and recover (1) the over- and under-recoveries of projected EE Program Costs through its DSMA Mechanism, pending reconciliation in subsequent rider periods, and approving the deferral of any costs incurred implementing the programs before the Commission issues an Order authorizing NIPSCO to recognize those costs through the ratemaking process; and (2) lost revenues for previous program years, including DSM programs subsequently discontinued.

The Commission's July 18, 2016 Order in Cause No. 44688 approved NIPSCO's Rider 783 – Demand Side Management Adjustment Mechanism and Appendix G – Demand Side Management Adjustment Mechanism (DSMA) Factor, to become effective October 1, 2016. The Commission approved NIPSCO's proposal to reset lost revenues in its DSMA Mechanism, effective upon the implementation of new base rates (October 2016), to eliminate lost revenues attributable to all energy efficiency measures installed on or before December 31, 2014.

As noted above, the DSM 11 Order authorized NIPSCO to transition from semi-annual DSM filings to an annual DSM filing. Going forward, the annual DSM filing factors will be applicable for the period January through December of a calendar year, or until replaced by

[1] Or until NIPSCO submits and receives approval of a plan under Ind. Code § 8-1-8.5-10, whichever occurs earlier.

different factors approved in a subsequent filing. The DSM 11 Order also authorized NIPSCO to change from November 15 to May 15, the date by which eligible customers must notify ~~NIPSCO of their intent to opt-out of or opt-in to NIPSCO's Electric DSM Program.~~

4. **Requested Relief.** Petitioner now requests Commission approval of DSMA Factors to be effective for the billing cycles for the months of January through December 2018. The factors proposed in this proceeding include (1) projected start-up, implementation, and administrative costs for the period of January through December 2018, and (2) actual EM&V costs for the periods January through December 2015 and January through December 2016, and projected lost revenues for the period January through December 2018. This filing also includes NIPSCO's annual reconciliation of (1) actual EM&V costs for the periods January through December 2015 and January through December 2016, (2) actual program costs for July through December 2016, (3) actual revenues for July 2016 through February 2017, and (4) actual lost revenues for January through December 2016.[2]

Petitioner also requests continued authority to defer as a regulatory asset or regulatory liability the over- and under-recoveries of projected EE Program Costs incurred implementing the DSM programs until the Commission issues an order authorizing Petitioner to recover these costs through the ratemaking process. NIPSCO will defer these costs on the balance sheet as a regulatory asset in Account 182.3 – Regulatory Asset or a regulatory liability in Account 254 – Other Regulatory Liabilities, depending on the net balance of EE Program Costs.

5. **Implementation of DSM Programs.** NIPSCO Witness Victoria A. Vrab, Director of Demand Side Management Programs, described NIPSCO's EE Program for Program Year 2017, the administration of those programs, and an overview of the current performance of NIPSCO's EE Program, as shown on Attachment 2-B and summarized as follows:

- Residential Heating, Ventilation and Air Conditioning Rebate Program – As of March 31, 2017, this program achieved 21% of its savings goal. This program has traditionally performed well within NIPSCO's service territory and is anticipated to continue to perform well in 2017.
- Residential Lighting Program – As of March 31, 2017, this program achieved 9% of its savings goal and is on track to meet its annual savings goal. Lighting events continue throughout NIPSCO's service territory as a means of educating the customers and encouraging participation in the program.
- Residential Home Energy Analysis ("HEA") Program – As of March 31, 2017, this program achieved 0% of its savings goal. This program has not traditionally

[2] NIPSCO's transition to an annual DSMA filing, approved in NIPSCO's DSM 11 proceeding, caused a one-time mismatch of reconciliation time periods.

performed well within NIPSCO's service territory which is why NIPSCO has scaled it back for 2017.

- Residential Appliance Recycling Program – As of March 31, 2017, this program achieved 17% of its savings goal. NIPSCO anticipates this program will meet 100% of its savings goal by year-end.

- Residential School Education Program – Even though 0% of the savings goal was achieved as of March 31, 2017, over 6,500 school kits were enrolled for the spring semester. As in previous years, this program continues to be well received within NIPSCO's service territory, and it is anticipated to achieve 100% of the goal for 2017.

- Residential Behavioral Program – As of March 31, 2017, this program achieved 0% of its savings goal. NIPSCO chose to return to a more traditional program in 2017 through the distribution of paper and email reports. Due to delays in contract negotiations, the first set of reports were not sent until the month of June.

- Residential Income Qualified Weatherization ("IQW") Program – As of March 31, 2017, this program achieved 0% of its savings goal. Lockheed Martin continues to collaborate with ARCA, Urban Efficiency and local CAP agencies to implement the program.

- Commercial and Industrial ("C&I") Prescriptive Program – As of March 31, 2017, this program achieved 31% of its savings goal. Lockheed Martin has a "pipeline" of anticipated savings, 1,311,706 kilowatt hours ("kWh"), to better align the program expectations. These anticipated savings are based on those applications that require preapproval due to the larger incentive amount and are in addition to the savings already achieved.

- C&I Custom Program – As of March 31, 2017, this program achieved 22% of its savings goal. As with most Custom projects, the timing for the completion of such major projects is often difficult to accurately predict. The pipeline of additional savings was 2,098,153 kWh at the end of March.

- C&I New Construction Program – As of March 31, 2017, this program achieved 8% of its savings goal. The market has not been as receptive to the program as Lockheed Martin initially expected. Lockheed Martin continues to look for ways to increase participation. In addition to the savings achieved, Lockheed Martin had 4,421,072 kWh in the pipeline at the end of March.

- C&I Small Business Direct Install ("SBDI") Program – As of March 31, 2017, this program achieved 22% of its savings goal, with an additional 250,916 kWh in the pipeline. To increase participation, the program design was optimized to modify several of the SBDI measures based on trends from 2016.

- C&I Retro Commissioning ("RCx") Program – As of March 31, 2017, this program achieved 0% of its savings goal. While Lockheed Martin still considers this program to have potential within NIPSCO's service territory, there are currently no projects in the pipeline. To encourage participation, Lockheed Martin removed the request for qualifications process requirement and now allows any approved trade ally to apply for RCx measures.

Ms. Vrab explained the role NIPSCO's Oversight Board ("OSB") plays in program design and budget modifications. The Commission established NIPSCO's OSB through its July 27, 2011 Order in Cause No. 43912. NIPSCO continues to strengthen its relationship with its OSB and works with OSB members on program designs for its 2016-2018 EE Program. NIPSCO's OSB provides general recommendations throughout the year and approves program designs and budgets as provided within Commission approval and the OSB governance document. Over the course of the program year, the OSB monitors the programs and provides oversight of and approval for programmatic changes. Ms. Vrab also testified concerning NIPSCO's proposal to use DSM budget dollars for a new market potential study (based on the expected cost, $310,571 is allocated to electric in this filing) and stated that the OSB will be involved in the ultimate selection of the vendor for the market potential study.

NIPSCO Witness Derric J. Isensee, Executive Director of Rates and Regulatory Finance, sponsored Attachment 1-C, which is a cost allocation matrix that shows (1) the cost type (Program Costs, EM&V Costs, Lost Revenues) relating to Schedules 2.1, 2.2, 2.3, 2.4, 4.1A, 4.1, 4.2, 4.3, 4.4, 5A, 5.1, 5.2, 5.3, and 5.4, (2) the cost component (Forecast, Actual, Variance), (3) the period for each cost type; (4) the measures installed period; and (5) the parties who were allocated the costs (Opt-In Customers, Opt-Out 1 Customers, etc.).

6. <u>Recovery and Reconciliation of Program Costs and Revenues</u>. Ms. Vrab sponsored Attachment 2-A, Schedule 1, which details the projected and reconciled costs for the recovery period January through December 2018. This filing reconciles Program Costs incurred for July through December 2016 and includes projected costs for January through December 2018.

Ms. Vrab explained the exhibit supporting Schedule 1, Attachment 2-C is the work product that feeds into Schedule 1 showing the actual costs incurred from July through December and the projected costs for January through December 2018. Ms. Vrab testified the projections for the period January through December 2018 were based on a forecast provided by Lockheed Martin, which was influenced by 2016 and 2017 activity.

Ms. Vrab also testified the projected costs for January through December 2018 were $17,280,458 and the actual EM&V costs for the period January 2015 through December 2016 were $305,224. The actual costs incurred were $3,176,114 less than previously billed, resulting in an over-recovery of that amount. The Residential HEA Program, the C&I Custom Program, and the C&I Prescriptive Program were the main contributors to the over-recovery.

As shown on Attachment 2-A, Schedule 1, adding $17,280,458, the projected costs for January through December 2018, to $305,224, the actual EM&V costs for January 2015 through December 2016, and then subtracting $3,176,114, the over-recovery of projected costs for July through December 2016, results in $14,409,569, the total Program Costs to be collected in this filing.

Mr. Isensee testified about NIPSCO's request for continued authority to defer as a regulatory asset or regulatory liability the over- and under-recoveries of projected Program Costs and Program Costs incurred implementing the 2016-2018 EE Program until the Commission issues an order authorizing Petitioner to recognize these costs through the ratemaking process. NIPSCO will defer these costs on the balance sheet as a regulatory asset in Account 182.3 – Regulatory Asset or a regulatory liability in Account 254 – Other Regulatory Liabilities, depending on the balance of Program Costs.

OUCC witness Crystal L. Barrett, Utility Analyst in the Electric Division, concurred with NIPSCO's calculations and agreed that the Residential HEA Program, the C&I Custom Program, and the C&I Prescriptive Program were the main contributors to the over-collection/variance related to program costs, but noted that contributing to the program cost variance is the large under-collection in the C&I Small Business Direct Install Program. Ms. Barrett commented on the mismatch in reconciliation periods caused by NIPSCO's transition to an annual DSMA filing. She noted that while she would typically recommend the reconciliation period for expenses to match the period for revenues, in this case, she supports NIPSCO's proposal to include two additional months of revenues as this process allows customers to benefit from the over-collection rather than having NIPSCO retain the over-collection for an extra year.

7. **Calculation and Reconciliation of Lost Margins.** Ms. Vrab sponsored Attachment 2-A, Schedules 3.1, 3.2, 3.3, 3.4, which shows the energy and demand savings used in the calculation of lost revenues, and Schedule 3A, which shows a summary of the reconciliation of the previous reconciliation period. NIPSCO's request in this filing includes projected lost revenues for January through December 2018 and NIPSCO's annual reconciliation of lost revenues for January through December 2016, all intended to be recovered through this proceeding.

Ms. Vrab explained the exhibits supporting Schedule 3. Attachment 2-D summarizes the actual EM&V related charges that directly feed to Schedule 1. Attachment 2-E is the work product that feeds into Schedule 3 and shows the detailed calculations supporting the energy and demand savings. Attachment 2-F shows the update to program titles on the Schedules.

According to Schedule 3A, the projected lost revenues for January through December 2016 were $12,339,360 and, after the reconciliation, the actual revenues for January through December 2016 should have been $15,859,740, resulting in an under-recovery of $3,520,380. There were variances throughout energy and demand across all programs. The main contributors to this under-collection were the C&I SBDI Program and the C&I Prescriptive Program.

OUCC witness Barrett concurred with NIPSCO's calculation of projected and reconciled lost revenues in this filing.

8. **Resulting DSMA Factors.** Mr. Isensee explained NIPSCO's proposed DSMA Factors calculation. He testified the proposed ratemaking treatment is consistent with the 44634 Order. He sponsored Attachment 2-A, Schedules 2, 4, 5, 6 and 7, which show (1) projected Program Costs allocated to each rate schedule, (2) the allocation of lost revenues based on energy and demand by rate schedule and by Opt-Out Period, (3) reconciliation of revenues by rate class, and (4) the calculation of DSMA Factors by rate schedule.

Mr. Isensee testified the DSMA Factors are developed based on forecasted Program Costs and lost revenues (with the exception of EM&V costs which are recovered based on actual costs). The projected Program Costs are reconciled to actual Program Costs in a subsequent filing. As shown in Schedule 2, NIPSCO then allocates the projected Program Costs by program to the individual rate classes based on energy allocators consistent with the Commission's December 30, 2014 Order in Cause No. 43618 DSM 7 ("DSM 7 Order"). As shown in Schedules 4 and 5, NIPSCO allocates the projected lost revenues by program to the individual rate classes based on energy allocators consistent with the DSM 7 Order. Once NIPSCO allocates the Program Costs to the individual rate classes and performs a reconciliation of revenue collection, NIPSCO then calculates the DSMA Factors by dividing the cost per rate class by the respective forecasted usage. NIPSCO then adjusts the resulting DSMA Factors to reflect Utility Receipts Tax on Retail Sales.

Mr. Isensee sponsored Attachment 1-D, reflecting the DSMA Factors for recovery from January through December 2018. He also sponsored Attachment 1-E, showing the calculation of the estimated average monthly bill impact for a typical residential customer using (1) 698 kilowatt-hours ("kWh") per month is $1.63 (a $1.00 decrease in comparison to what a customer would pay using the current DSMA Factors) and (2) 1,000 kWh per month is $2.33 (a $1.44 decrease in comparison to what a customer would pay today using the current DSMA Factors). Ms. Barrett confirmed the accuracy of NIPSCO's calculation of its residential DSMA factor.

9. **Commission Findings.** Based on the evidence presented, we find that NIPSCO's proposed DSMA Factors are reasonable and properly calculated; therefore, we approve the DSMA Factors contained in Schedule 7 to be effective for the first billing cycle for the billing month of January 2018, to remain in effect through December 2018, or until replaced by different adjustment factors approved in a subsequent filing. We also find NIPSCO's request for continued authority to defer over- and under-recoveries of projected Program Costs and Program Costs incurred implementing DSM programs until the Commission issues an order authorizing Petitioner to recognize these costs through the ratemaking process to be reasonable, and accordingly we approve that request.

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

1. NIPSCO's request for approval of its revised DSMA Factors as set out in Schedule 7 (with estimated impact set forth in Petitioner's Attachment 1-E) is approved.

2. NIPSCO is granted continued authority to defer as a regulatory asset or regulatory liability the over and under recoveries of projected Program Costs and Program ~~Costs incurred implementing the DSM programs prior to the time the Commission issues an~~ order authorizing Petitioner to recognize these costs through the ratemaking process.

3. Prior to implementing the rate(s) NIPSCO shall file the tariff and applicable rate schedules under this Cause for approval by the Commission's Energy Division. Such rate(s) shall be effective on or after the order date subject to Division review and agreement with the amounts reflected.

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

ATTERHOLT, FREEMAN, HUSTON, WEBER, AND ZIEGNER CONCUR:

APPROVED: DEC 13 2017

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

Mary M. Becerra

Mary M. Becerra
Secretary of the Commission

ORIGINAL

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY ("NIPSCO") FOR (1) AUTHORITY TO MODIFY ITS RATES AND CHARGES FOR ELECTRIC SERVICE;(2) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES APPLICABLE THERETO; (3) APPROVAL OF REVISED DEPRECIATION ACCRUAL RATES; (4) INCLUSION IN ITS BASIC RATES AND CHARGES OF THE COSTS ASSOCIATED WITH CERTAIN PREVIOUSLY APPROVED QUALIFIED POLLUTION CONTROL PROPERTY PROJECTS; AND (5) APPROVAL OF VARIOUS CHANGES TO NIPSCO'S ELECTRIC SERVICE TARIFF INCLUDING WITH RESPECT TO THE GENERAL RULES AND REGULATIONS.	)	CAUSE NO. 43969 APPROVED: DEC 21 2011

ORDER OF THE COMMISSION

Presiding Officers:
David E. Ziegner, Commissioner
Aaron A. Schmoll, Senior Administrative Law Judge

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INDIANA UTILITY REGULATORY COMMISSION

CAUSE NO. 43969

INTRODUCTION

On November 19, 2010 Northern Indiana Public Service Company ("Petitioner," "Company" or "NIPSCO") filed its Petition and Notice of Intent to File in Accordance with Minimum Standard Filing Requirements with the Indiana Utility Regulatory Commission ("Commission") for (1) authority to modify its rates and charges for electric utility service; (2) approval of new schedules of rates and charges applicable thereto; (3) approval of revised depreciation accrual rates; (4) inclusion in its basic rates and charges of the costs associated with certain previously approved Qualified Pollution Control Property ("QPCP") projects; and (5) approval of various changes to its Electric Service Tariff including the general rules and regulations.

Petitions to Intervene were filed by NIPSCO Industrial Group ("Industrial Group"),[1] the City of Hammond, Indiana ("Hammond"), Indiana Municipal Utilities Group ("Municipal Utilities"),[2] NLMK Indiana f/k/a Beta Steel Corporation ("NLMK"), Citizens Action Coalition of Indiana, Inc., and the Board of County Commissioners of the County of Jasper (collectively referred to herein as "Intervenors"), all of which were granted, and made parties to this Cause. The Indiana Office of Utility Consumer Counselor ("OUCC") also participated in this proceeding as the statutory representative of the consumers.

On November 19, 2010, NIPSCO filed its prepared testimony and exhibits constituting its case-in-chief and the workpapers required by the Commission's Rules on Minimum Standard Filing Requirements, 170 IAC 1-5-1 ("MSFRs").[3] On December 15, 2010, OUCC filed a Notice Regarding Petitioners' Election on the Minimum Standard Filing Requirements Rules.

A Prehearing Conference was held on December 17, 2010 and a Prehearing Conference Order was issued on January 5, 2011, which established the agreed-to procedural schedule for this proceeding.[4]

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[1] NIPSCO Industrial Group is comprised of Accurate Castings, Inc.; ArcelorMittal USA; BP Energy; Cargill, Inc.; NLMK Indiana; Praxair, Inc.; United States Steel Corporation; USG Corporation; and Weil-McLain.

[2] Municipal Utilities is comprised of Town of Dyer, City of East Chicago, Town of Griffith, Town of Highland, Town of Munster, Town of Schererville, the City of Valparaiso and Town of Winfield.

[3] Petitioner filed Supplemental Information Related to Depreciation Study on November 19, 2010; Submission of Late-Filed Petitioner's Exhibit No. JDS-3 on January 19, 2011; Submission of Corrected Minimum Standard Filing Requirements on January 25, 2011; and Submission of Late-Filed Petitioner's Exhibit No. JDS-2 on February 9, 2011.

[4] 170 IAC 1-5-2(c)(4) provides an exception to complete a case filed under the MSFR beyond the typical 10-month period if exceptional circumstances so warrant. In order for the parties to agree to the schedule proposed, the parties proposed a schedule that provides for a Commission Order to be issued by December 30, 2011, which is beyond 12

During a technical conference held on February 9, 2011 it became apparent that the Commission, OUCC and Intervenors would be aided in their evaluation of NIPSCO's case-in-chief by the provision of additional information related to its cost of service study. NIPSCO agreed, at the Commission staff's request, to rerun the cost of service study to reflect current revenues from all existing rate classes and allocate NIPSCO's current costs to serve those same rate classes.

On February 18, 2011, NIPSCO, OUCC and Industrial Group filed an Agreed Motion for Continuance requesting additional hearing dates for NIPSCO's cost of service and rate design witnesses, which was granted by Docket Entry dated February 22, 2011. NIPSCO filed its Submission of Supplemental Cost of Service Study Information on February 22, 2011 and Additional Supplemental COSS Workpapers on February 24, 2011.

On March 21, 2011, Petitioner filed an Unopposed Motion for Continuation of Hearing, which was granted by Docket Entry dated April 4, 2011. On March 23 and April 1, 2011, Petitioner filed Revised Direct Testimony and Exhibits of its cost of service study and rate design witnesses and Revised Supplemental Cost of Service Study Information.

Pursuant to Ind. Code § 8-1-2-61(b), a public field hearing was held on April 7, 2011 in the City of Hammond, the largest municipality in Petitioner's electric utility service area. At the field hearing, members of the public were afforded the opportunity to make statements on the record or submit written comments to the Commission.[5]

On July 12, 2011, NIPSCO, OUCC, NLMK and Municipal Utilities filed a Notice of Settlement in Principle and Request for Attorneys' Conference. On July 18, 2011, NIPSCO, the OUCC, NLMK, Municipal Utilities and Industrial Group (the "Settling Parties") filed a Stipulation and Settlement Agreement ("Settlement") containing a proposed resolution of the issues in this proceeding. A copy of the Settlement Agreement is attached hereto and incorporated herein by reference.

In accordance with the agreed-to procedural schedule established in the Docket Entry dated July 21, 2011, Petitioner prefiled settlement testimony on July 22, 2011, the remaining Settling Parties filed settlement testimony on July 29, 2011, Hammond filed testimony responding to the Settlement on August 19, 2011, and the Settling Parties filed rebuttal testimony on August 31, 2011. The Commission issued a Docket Entry on June 7, 2011 and August 25, 2011, ordering Petitioner to respond to questions, to which Petitioner responded on July 12, 2011 and September 6, 2011, respectively. Following questioning from the Presiding Officers, Petitioner filed Supplemental Responses to the September 6 Responses on September 14, 2011.

A Settlement Hearing commenced on September 12, 2011. At that time, the direct and rebuttal testimonies and exhibits of the Settling Parties in support of, and Hammond's testimony responding to, the Settlement were admitted into evidence.

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months from the date of Petitioner's prefiling date. The Commission found that exceptional circumstances exist and that the underlying schedule is reasonable. The Commission also authorized the Presiding Officers to make further modifications to the underlying procedural schedule, for good cause shown.

[5] OUCC filed Written Comments of Members of the Public on April 29, 2011.

Having considered the evidence and being duly advised, the Commission now finds:

1. **Notice and Jurisdiction.** Due, legal and timely notice of the filing of the Petition in this Cause was given and published by Petitioner as required by law. Proper and timely notice was given by Petitioner to its customers summarizing the nature and extent of the proposed change in its rates and charges for electric service. Due, legal and timely notices of the public hearings in this Cause were given and published as required by law. Petitioner is a public utility as defined in Ind. Code § 8-1-2-1(a) and is subject to the jurisdiction of the Commission in the manner and to the extent provided by the laws of the State of Indiana. This Commission has jurisdiction over Petitioner and the subject matter of this proceeding.

2. **Petitioner's Characteristics.** Petitioner is a public utility with its principal place of business located at 801 East 86th Avenue, Merrillville, Indiana, and provides gas ("NIPSCO Gas") and electric service ("NIPSCO Electric") in Indiana. Petitioner is authorized by the Commission to provide electric utility service to the public in all or part of Benton, Carroll, DeKalb, Elkhart, Fulton, Jasper, Kosciusko, LaGrange, Lake, LaPorte, Marshall, Newton, Noble, Porter, Pulaski, Saint Joseph, Starke, Steuben, Warren and White Counties in northern Indiana.

3. **Existing Rates.** The Commission issued an Order in Cause No. 43526 on August 25, 2010 ("43526 Order"), which authorized the modification to NIPSCO's rates and charges for electric service; however, the resulting rates have not been implemented because, at the request of several parties, the Commission ordered a stay of NIPSCO's compliance filing pending this rate case proceeding. As a result, NIPSCO's currently effective basic rates and charges are those approved by the Commission in its Order dated July 15, 1987 in Cause No. 38045.

The 43526 Order also approved new depreciation accrual rates; however, as confirmed by the Docket Entry issued in Cause No. 43526 dated October 22, 2010, those new depreciation accrual rates were not to take effect unless and until the basic rates and charges approved in Cause No. 43526 were implemented. As a result, NIPSCO's currently effective depreciation accrual rates for its electric and common properties are based on a depreciation study prepared in its general rate proceeding in Cause No. 38045.

4. **Test Year and Rate Base Cutoff.** As provided in the Prehearing Conference Order, the test year to be used for determining Petitioner's actual and pro forma operating revenues, expenses and operating income under present and proposed rates is the twelve month period ended June 30, 2010, adjusted for changes that are fixed, known and measurable for ratemaking purposes and that will occur within twelve months following the end of the test year. The Prehearing Conference Order recognized that Petitioner may make proposals regarding rate adjustment mechanisms that are not limited by the 12-month adjustment period. The Prehearing Conference Order provided that the general rate base cutoff shall reflect used and useful property at the end of the test year.

5. **Relief Requested.** In its case-in-chief, NIPSCO sought approval: (1) of changes to its basic rates and charges for electric utility service to provide NIPSCO with the opportunity to earn a fair rate of return on the fair value of its property, (2) of changes to its Electric Service Tariff, including the Series 600 Rate Schedule, revised reconnection charges, standard contracts

and street lighting tariffs and miscellaneous changes to its General Rules and Regulations and (3) to revise its depreciation accrual rates.

In its case-in-chief, NIPSCO also sought approvals in this Cause which are consistent with the findings made by the Commission in its 43526 Order, with respect to:

(1) modifications to its Environmental Expense Recovery Mechanism ("EERM") to track emission allowances purchases and sales;

(2) amortization of deferred depreciation and carrying charges associated with Petitioner's Sugar Creek Generating Station ("Sugar Creek");

(3) the sharing mechanism for off system sales ("OSS") margins;

(4) the Regional Transmission Organization ("RTO") Tracker to track Midwest Independent Transmission System Operator, Inc. ("MISO") non-fuel charges and credits and OSS sharing;

(5) the Resource Adequacy ("RA") Tracker;

(6) modifications to its purchased power benchmark;

(7) modifications to its General Rules and Regulations (except as expressly proposed for further modification in Petitioner's evidence in this Cause); and

(8) reflecting in its basic rates and charges capital costs and operating expenses associated with QPCP projects previously approved by the Commission in Cause Nos. 42150 and 43188 that were completed and in-service at the end of the test year in that Cause and that are currently being recovered through the Environmental Cost Recovery Mechanism ("ECRM"), and adjusting the ECRM to eliminate costs relating to those projects upon the effective date of the new base rates approved herein, subject to any necessary variance reconciliations.

6. Petitioner's Evidence. Prior to the submission of the Settlement, NIPSCO presented extensive evidence, which is briefly summarized here and further considered in the discussion of the Settlement below.

A. Robert C. Skaggs. Robert C. Skaggs, Jr., President and Chief Executive Officer of NiSource Inc. ("NiSource"), provided an overview of NiSource and its corporate structure, and updated the Commission on NiSource's strategic direction. Mr. Skaggs touched on the operation and management of NIPSCO Electric and how it fits into NiSource's strategy. He addressed recent improvements in NiSource's financial health, most notably (i) NiSource's credit profile and the benefits to all stakeholders associated with a continuation of the recent improvement in NiSource's financial outlook and (ii) the recently completed $400 million offering of NiSource common stock.

B. Jimmy D. Staton. Jimmy D. Staton, Executive Vice President and Group Chief Executive Officer for NiSource's Northern Indiana Energy Business Segment, provided an overview of NIPSCO's organizational structure and electric operations. He explained the unique challenges faced by NIPSCO and briefly summarized the relief requested by NIPSCO in its case-in-chief.

C. Frank A. Shambo. Frank A. Shambo, Vice President, Regulatory and Legislative Affairs, provided a brief background of NIPSCO's existing electric rates. He explained why NIPSCO filed this case, including the key drivers and the relationship to NIPSCO's request in Cause No. 43526 and provided an overview of NIPSCO's earnings situation. He explained NIPSCO's approach to this case and its philosophy as it moves forward in this proceeding. He provided an overview of the objectives NIPSCO used in developing the rates proposed in this proceeding and explained key cost allocation and rate design criteria used in the development of rates and how those criteria align with the established objectives. He also provided a summary of NIPSCO's tariff relief. He discussed the appropriate return on its used and useful assets proposed in this proceeding and explained one pro forma adjustment made to test year operating results.

D. Karl E. Stanley. Karl E. Stanley, Vice President, Commercial Operations, described NIPSCO's focus on customer service by (1) conveying NIPSCO's recent success in improving various utility customer satisfaction measurements and metrics and (2) describing projects that the Company has implemented or will implement to further improve customer satisfaction. He also described adjustments that will be made to the revenue requirement due to the purchase or sale of capacity credits. He stated these capacity credits are required to fulfill MISO requirements whereby a Load Serving Entity ("LSE") is required to hold sufficient capacity to serve the needs of its customers.

E. Timothy A. Dehring. Timothy A. Dehring, Senior Vice President, Transmission and Engineering, described NIPSCO's electric transmission and distribution systems. He discussed the Company's customer service and electric reliability programs. He also explained the need for certain pro forma expense adjustments.

F. Philip W. Pack. Philip W. Pack, Director, Generation Support Services and Major Projects, described NIPSCO's generation fleet and the reliability of its coal-fired units. He also provided an explanation of an operation and maintenance ("O&M") expense adjustment for the Bailly gypsum disposal.

G. Linda E. Miller. Linda E. Miller, Executive Director, Rates and Regulatory Finance, presented evidence regarding NIPSCO's net original cost rate base, capital structure and weighted cost of capital. She also presented the results of operations during the test year and on a pro forma basis at both present and proposed rates. She provided an overview of NIPSCO's accounting practices, including its audits, control and processes. She sponsored NIPSCO's per book financial statements for the test year and explained how common costs are allocated between NIPSCO's gas and electric business. She described NIPSCO's request for approval of proposed depreciation rates on an account-by-account basis.

H. Susanne M. Taylor. Susanne M. Taylor, Controller of NiSource Corporate Service Company ("NCSC"), provided background about NCSC and the role it serves within NiSource and provided support for the annualized level of NCSC charges billed to NIPSCO in the historical test year and the amount allocated to NIPSCO Electric. She supported and provided an explanation of each of the pro forma adjustments for fixed, known and measurable changes applicable to NIPSCO Electric occurring during the adjustment period. She provided information pertaining to the types of costs that have been allocated to NIPSCO and the mechanism for billing the NCSC costs to NIPSCO. She sponsored (1) a detailed breakdown of total NCSC contract billings by individual expense line item allocated to NIPSCO and then to NIPSCO Electric and (2) monthly overhead allocation percentages that are billed to NIPSCO.

I. John J. Spanos. John J. Spanos, Vice President, Valuation and Rate Division of Gannett Fleming, Inc., sponsored the results of his depreciation analysis related to NIPSCO's electric and common plant as of June 30, 2010 (the "Depreciation Study"). Mr. Spanos explained the methods and procedures used in the Depreciation Study and proposed new depreciation accrual rates. As part of the Depreciation Study, Mr. Spanos also developed proposed depreciation accrual rates for Sugar Creek.

J. Alberto D. Romero. Alberto D. Romero, Director of Taxes of NCSC, presented and supported NIPSCO's federal and state income tax expense adjustments and the adjustments for taxes other than income included in the cost of service shown in the accounting exhibits of Ms. Miller.

K. Vincent V. Rea. Vincent V. Rea, Assistant Treasurer of NiSource, testified about NIPSCO's debt financing activities, credit ratings and cost of debt.

L. Paul R. Moul. Paul R. Moul, Managing Consultant at the firm P. Moul & Associates, presented evidence, analysis and a recommendation concerning the appropriate cost of common equity for NIPSCO. He also addressed the fair rate of return applicable to NIPSCO's fair value rate base.

M. John P. Kelly. John P. Kelly, Executive Advisor of Concentric Energy Advisors, Inc. ("Concentric"), addressed the fair value of NIPSCO's electric utility assets. He described the valuation study upon which his conclusions were based.

N. Cecelia Largura. Cecelia Largura, Director, Strategic Execution, described the electric load research methodology used in support of NIPSCO witness J. Stephen Gaske's testimony on behalf of NIPSCO's 2010 Allocated Cost of Service Study ("ACOSS") and the methodology used to evaluate load characteristics by class during the test year. She also explained NIPSCO's weather normalization procedures.

O. John D. Taylor. John D. Taylor, Senior Consultant of Concentric, supported the ACOSS. Specifically, he explained the various special studies that were utilized within the ACOSS to apportion the various categories of plant and O&M expenses to the respective customer classes. He also described the general need for, and methodology of, the special studies and provided details on how these studies were conducted for NIPSCO's ACOSS.

P. J. Stephen Gaske. J. Stephen Gaske, Senior Vice President of Concentric, discussed the purpose of an allocated cost of service study and described the Concentric Cost of Service Model used in conducting NIPSCO's electric cost of service study. He described various principals of cost allocation, factors that influence the cost allocation framework, and the underlying methodology and basis used in NIPSCO electric cost of service studies. He described the relative cost studies and other analyses employed to apportion the various categories of plant and O&M expenses to the respective customer classes. He presented the class-by-class rate of return results and corresponding revenue surpluses or deficiencies from NIPSCO's ACOSS for (i) the 800 Series rate classes that were in effect during the test year and (ii) the 600 Series rate classes that are being proposed in this proceeding, including the resulting unit costs by class for customer, demand and energy-related costs within the ACOSS. He also described the method used to allocate NIPSCO's revenue deficiency to the various rate schedules. Finally, he described the process used to design the rates that are being proposed in this proceeding and discussed the customer impacts of the proposed rate increases.

Q. Curt A. Westerhausen. Curt A. Westerhausen, Director of Rates and Contracts, described NIPSCO's proposed IURC Electric Service Tariff, Original Volume No. 12, including the Schedules of Rates ("Rates"), Riders and General Rules and Regulations ("Rules") (the "Proposed Tariff"). He explained how the Proposed Tariff differs from NIPSCO's IURC Electric Service Tariff, Original Volume No. 10, currently on file with the IURC (the "Current Tariff") and provided support for several proposed changes to NIPSCO's Current Tariff.

7. The Settlement. The Settlement is attached hereto and incorporated herein by reference. The Settlement, which the Settling Parties, i.e., NIPSCO, OUCC, NLMK, Municipal Utilities and Industrial Group, agree is fair, just and reasonable, presents a comprehensive resolution of all matters pending before the Commission in this Cause. The Settlement states that the Settling Parties agree that resolution of the individual issues specified in the Settlement are reasonable for purposes of compromise as part of the overall settlement package. The Settlement provides as follows:

A. Revenue Requirement and Net Operating Income.

(a) Revenue Requirement. The Settling Parties agreed that NIPSCO's base rates will be designed to produce \$1.355 billion, which is the Revenue Requirement of \$1.401 billion less \$46 million of Other Revenues. This Revenue Requirement is a decrease of \$68 million from the amount originally requested by the Company. Based on test-year fuel costs, this provides for a margin requirement of \$927 million plus \$12 million in non-trackable fuel.

(b) Net Operating Income. The Settling Parties agreed that NIPSCO's Revenue Requirement in Paragraph B.6.(a) of the Settlement results in a proposed authorized net operating income ("NOI") of \$188.9 million.

B. Fair Value Rate Base, Capital Structure and Fair Return.

(a) Fair Value Rate Base. NIPSCO agreed that its weighted cost of capital times its original cost rate base yields a fair return for purposes of this case. Based upon this agreement, the Settling Parties concurred that NIPSCO should be authorized a fair rate of return of 6.98%, yielding an overall return for earnings test purposes of \$188.9 million, based upon:

(i) an original cost rate base of \$2.7 billion, inclusive of materials, supplies and production fuel, as proposed in NIPSCO's case-in-chief;

(ii) NIPSCO's capital structure; and

(iii) an authorized return on equity ("ROE") of 10.2%.

NIPSCO's sum of the differentials, commonly referred to as the "earnings bank" computed under Ind. Code § 8-1-2-42.3, shall be re-set to $200 million.

(b) Capital Structure and Fair Return. Based on the following capital structure, the 10.2% ROE and cost of debt/zero cost capital as filed, the overall weighted average cost of capital ("WACC") is computed as follows:

	% of Total	Cost	WACC
Common Equity	46.53%	10.20%	4.75%
Long-Term Debt	32.46%	6.42%	2.08%
Customer Deposits	2.32%	4.43%	0.10%
Deferred Income Taxes	13.48%	0.00%	0.00%
Post-Retirement Liability	4.65%	0.00%	0.00%
Post-1970 ITC	0.56%	8.65%	0.05%
Totals	100.0%		6.98%

(c) Environmental Project Financing. The Settling Parties agreed that NIPSCO should finance, in aggregate, the projects for which it receives a Certificate of Public Convenience and Necessity in Cause No. 44012 with at least 60% debt capital.

C. Depreciation and Amortization Expense.

(a) Depreciation Expense. The Settling Parties stipulated that the depreciation accrual rates recommended by Mr. Spanos in the Depreciation Study should be approved, except for changes set forth in Joint Exhibit A that are based upon proposed changes in specified net salvage percents and which will reduce pro forma depreciation expense by $4.9 million. Joint Exhibit A contains a spreadsheet showing the proposed depreciation rates by class of property.

(b) Amortization Expense. The Settling Parties stipulated that annual amortization expense shall be $36.5 million, includingamortization of software and the following items:

(i) Rate case expenses of $0.770 million for this case ($2.3 million amortized over a period of three (3) years). After the completion of the three (3) year period, NIPSCO agrees to make a tariff filing that will reflect the reduction in amortization expense.

(ii) Deferred MISO costs, amortized and recovered over a period of four (4) years. Amounts included in this case were estimated through June 30, 2011. Costs will continue to be deferred until the effective date of new rates. Any difference between the estimate and the actual costs incurred will be included in the RTO tracker approved in Cause No. 43526.

(iii) Deferred Sugar Creek depreciation and carrying charges, through June 30, 2011, amortized and recovered over five (5) years. The Settling Parties agree that Sugar Creek depreciation and carrying charges may continue to be deferred from July 1, 2011 through December 31, 2011 or the implementation of new basic rates and charges, whichever occurs earlier. These amounts will remain as a regulatory asset on NIPSCO's books and records, but shall accrue no additional carrying charges, and NIPSCO may request recovery of the deferred amount in NIPSCO's next general rate case; provided the other Settling Parties reserve the right to contest the recovery of those amounts.

D. Operating Results at Current and Proposed Rates. Joint Exhibit B contains a Statement of Operating Income for the twelve months ended June 30, 2010 shown on an actual basis, and with pro forma adjustments at current and proposed rates per NIPSCO's filed request and to reflect the provisions of this Agreement.

E. Cost Allocation and Rate Design. The Settling Parties agreed that rates should be designed in order to allocate the revenue requirement to and among NIPSCO's customer classes in a fair and reasonable manner. For settlement purposes, the Settling Parties agreed that NIPSCO should generally design its rates using the structure of its existing 800 Series tariffs.

As noted above, the Settling Parties agreed that NIPSCO's settlement base rates in total will be designed to produce $1.355 billion. Joint Exhibit C attached to the Settlement is a table that contains the percentages and dollar amounts of revenue allocatedto the various customer classes. The Settling Parties agreed to the rate design specifics summarized in Joint Exhibit D attached to the Settlement.

The Settling Parties agreed that the proposed cost allocation results in fair and reasonable rates and charges.

F. Demand Allocators. The Settling Parties agreed that NIPSCO's demand allocators for purposes of the RTO Tracker and RA Tracker are set forth in Table 1 of Joint Exhibit E. The demand allocators for purposes of the RA Tracker will be based upon those set forth in Joint Exhibit E modified to reflect the amount of interruptible load contained in Rates 632, 633 and 634.

G. ECRM and EERM Factors. The ECRM and EERM factors are approved after the expenditures have occurred, and therefore, the Settling Parties agreed that the O&M and depreciation expense on the projects being added to rate base in this proceeding will continue to be deferred until the effective date of the rates approved in this Cause, and all such deferred costs will be recovered in the appropriate EERM filing.

H. Interruptible Credit. The Settling Parties agreed that NIPSCO should be authorized to implement Rider 675, which is attached to the Settlement as Joint Exhibit F and that the credits paid under the provisions of Rider 675 should be recovered from ratepayers, with 75% of the costs recovered through NIPSCO's RA Tracker as the demand component and 25% of the costs recovered through NIPSCO's Fuel Adjustment Clause ("FAC") mechanism as the energy component. The Settling Parties further agreed that the limit on megawatt ("MW") eligibility should be 500 MW, and the maximum amount to be paid in any calendar year under Rider 675 is $38 million.

I. Temporary, Backup and Maintenance Service. The Settling Parties agreed that NIPSCO should be authorized to implement Rider 676, which is attached to the Settlement as Joint Exhibit G.

J. The Settling Parties agreed that those facilities:

served under Rate 832 on June 30, 2010;

eligible for Rate 832 on June 30, 2010, but for being on a Special Contract or on Rate 845; or

located behind the meter of a facility eligible under Rate 832 and which facility would have been eligible under Rate 832,

are grandfathered into Rate 632 and those facilities shall remain eligible for Rate Schedule 632, regardless of any change in name, or ownership, or operation.

K. The Settling Parties agreed that a voltage adjusted FAC may be appropriate, and the Parties agreed to work together to determine the appropriate mechanism to be implemented. Upon reaching a resolution of that issue, the Parties will file a separate petition with the Commission.

L. Accounting Reporting. NIPSCO agreed to file separate gas and electric income statements with the Commission annually in April based on the previous calendar year. NIPSCO agreed to ensure that its financial reports are transparent and verifiable for future OUCC financial audits. NIPSCO agreed to work cooperatively with OUCC to facilitate the auditing function.

M. OUCC Audits. NIPSCO agreed in Cause No. 38706-FAC71S1 to fund OUCC actual audit or consulting fees up to an annual maximum of $100,000 per year for the purpose of conducting a review and audit of NIPSCO's hedging program. NIPSCO agreed that the fees may be utilized by OUCC to conduct reviews with respect to any management of fuel, purchased power, off-system sales, use of interruptible resources, or other tracking mechanisms.

N. General Rules and Regulations and Tariffs. The Settling Parties agreed that NIPSCO will make certain modifications to the General Rules and Regulations and Tariffs initially proposed in this proceeding, and the Settling Parties will jointly submit those revised General Rules and Regulations and Tariffs in support of approval of this Agreement. Joint Exhibit H to the Settlement is Rule 10.2 which is included in the General Rules and Regulations.

O. Final True-Up of Customer Credit. Upon the effective date of new rates following the issuance of a Final Order in this proceeding, the revenue credit and the sharing mechanism approved in Cause No. 41746 will cease. After reconciliations of the revenue credit have been performed for all billed months, the final balance of any over or under credit will be included in the variance in the FAC filing that follows the final revenue credit reconciliation month and shall be specifically identified.

Finally, the Commission notes the Settlement states that the Settling Parties agree that the Settlement and each term, condition, amount, methodology and exclusion contained therein reflects a fair, just and reasonable resolution and compromise for the purpose of settlement.

8. Testimony in Support of the Settlement Agreement. NIPSCO witnesses Shambo, Miller, Westerhausen and Spanos presented testimony in support of the Settlement. OUCC witness Tyler E. Bolinger and Industrial Group witnesses James R. Dauphinais and Nicholas Phillips, Jr. also presented testimony in support of the Settlement.

A. NIPSCO's Evidence in Support of Settlement.

(a) Frank A. Shambo. Mr. Shambo (1) provided an overview of why the Settlement is in the public interest, including the regulatory background related to this proceeding; (2) supported the revenue allocation proposed in the Settlement; (3) provided a general description and explanation of the key parts of the Settlement rate design; (4) explained the rationale for interruptible Rider 675; (5) explained why Rider 676 is offered; (6) provided support for the agreed-to ROE, overall return and changes to NIPSCO's earnings bank; and (7) described why the Settlement is in the public interest.

(1) Overview of Settlement. Mr. Shambo testified the Settlement resolves the issues in this proceeding as well as the issues currently pending in Cause No. 43526 in a fashion that balances the needs of NIPSCO's customers, the various parties and NIPSCO while also resolving a number of regulatory matters along the way. He stated the Settling Parties have specifically agreed that the issuance of an order approving the Settlement without any material modification or further condition shall terminate this proceeding, shall supersede the relief approved in the 43526 Order, including its associated compliance filings and shall conclusively resolve both proceedings. The Settlement also will conclude the bridge agreement and settlement with NLMK approved in Cause No. 43866 and the bridge agreement and settlement with BP Products North America, Inc. approved in Cause No. 44046 once new rates become effective.

Mr. Shambo stated that ultimately the Settlement falls within the broader public interest by providing all customer segments with a reasonable outcome and providing NIPSCO the opportunity to earn a fair return so that it can invest in northern Indiana's energy infrastructure, help fuel job creation and economic growth and provide customers with means to manage their energy consumption and bills.

Mr. Shambo noted that this proceeding was filed during a challenging economic period, specifically in NIPSCO's service territory. Northwest Indiana continues to have recession characteristics of high unemployment, under-employment, income challenges, and large industrial customers positioned in an ever more competitive world market. Mr. Shambo stated that the Settlement is the culmination of NIPSCO's efforts to work with its largest customers to develop an appropriate service structure and provide an opportunity to transition to new basic rates and charges. Mr. Shambo noted these industries are important because they not only invest in our state, but they provide a large number of jobs in NIPSCO's service territory as well as tax revenue and property tax base for the region and the state. He testified that jobs are especially critical in Northwest Indiana and that families depend upon a favorable manufacturing environment to retain and attract jobs.

Mr. Shambo stated that the region needs these companies to be competitive to avoid expansion of the ongoing economic downturn. He testified NIPSCO has kept this in mind in this proceeding, and has helped to respond to these drivers in the Settlement, including enhancements to Rider 675 – Interruptible Industrial Service, Rider 676 – Back-Up, Maintenance and Temporary Industrial Service and the introduction of Rate 634 – Industrial Power Service for Air Separation & Hydrogen Production Market Customers. He stated that while the increase for the large industrial customer class is over 20%, they have the ability to mitigate this increase in large part through interruptible options.

Mr. Shambo testified that, in addition to being sensitive to the needs of industrial customers, NIPSCO is also concerned that local poverty levels are high. He stated that, based upon what NIPSCO sees at the local agencies and through requests for assistance, low-income is also a consideration for purposes of evaluating an appropriate outcome to this proceeding. He stated that a related consideration is the ripple effect that can be caused by large residential increases. Low income customers may need further assistance if increases are very large and state agencies are already challenged in meeting the need for assistance.

Mr. Shambo testified that NIPSCO considered all of these factors, and believes that the Settlement reasonably balances (1) the need to retain and attract jobs in the manufacturing industry, (2) the need to mitigate the impact on residential customers and other sectors, and (3) NIPSCO's need to attract capital on reasonable terms to finance ongoing capital programs, including federally mandated environmental compliance facilities that are the subject of Cause No. 44012. He stated that an average $3.33 increase per month is a manageable amount per household. The Settling Parties have agreed that the residential customer charge should only be increased to $11 per month.

In response to questioning from the Presiding Officers, Mr. Shambo further explained the impact of the Settlement on residential customers. He testified the most appropriate way to view the impact is with current fuel costs and various tracker levels. See Petitioner's Exhibit No. 1-S, IURC Set 2-001 Attachment A, page 2 of 2. Assuming the Settlement were approved before the end of calendar year 2011, this analysis reveals that a residential customer using 688 kWh per month would see an increase from $80.43 to $83.10, or $2.67 per month (3.32%).[6]

Mr. Shambo testified the specific objectives addressed in the Settlement include (1) resolution of overall revenue allocation, (2) transitioning industrial customers to full tariffed

6 After implementation of NIPSCO's proposed Demand Side Management Adjustment factor currently pending in Cause No. 43618 DSM 1.

rates from less than tariff rates pursuant to expiring or expired special contracts, (3) concern about residential burden, and (4) mitigating the effect on municipalities and commercial customers.

Mr. Shambo testified the Settlement achieves resolution and compromise to the satisfaction of all customer interests while addressing these key objectives. He stated the Settling Parties represent all classes and some of them represent specific needs within those classes.

Mr. Shambo testified that other customers (not including special contract or economic development rider customers) were receiving a customer credit established as a result of a settlement in the rate investigation in Cause No. 41746. He stated this served as another item for the parties to address while reasonably transitioning customers to full tariff rates. Mr. Shambo testified the customer credit will terminate upon implementation of new rates resulting from this proceeding.

(2) Revenue Allocation. Mr. Shambo testified that the class allocation agreed to in the Settlement is fair and reasonably meets the Settling Parties' key objectives. The revenue increase to residential customers (Rate 611) is 4.788%, the revenue increase to industrial customers (Rates 632, 633 and 634) averages 20.317% and the revenue increase to larger general service classes (Rates 621, 623, and 624) averages 10.586%; the revenue allocation increase was zeroed out to municipalities that utilize NIPSCO's street lighting and traffic lighting rate schedules; and the revenues for no class increased, other than the large industrials, by more than 12%. He stated that while it is true that certain special contract industrial customers will experience a greater increase moving to full tariff rates; the impact is one that they can choose to manage through the utilization of Rider 675 – Interruptible Industrial Service.

(3) Description and Explanation of the Key Parts of the Settlement Rate Design. Mr. Shambo explained that NIPSCO simplified its approach by building its service structure from firm services while making few adjustments to determinants overall so that the parties could more easily see the derivation of rates under those services. He testified the Settling Parties have agreed to a treatment of interruptibility (both for its provision of service and recovery of associated credits) that is explicit and clear for customers to understand. He stated this service has also incorporated the input of NIPSCO's large industrial customers, and NIPSCO hopes that it provides a positive working model for years to come.

Mr. Shambo testified Joint Exhibit D to the Settlement serves as the appropriate starting point as a summary of the rate design parameters agreed to by the Settling Parties. He stated that generally speaking, NIPSCO's proposed use of the 600 Series rate structure has been maintained and it closely aligns with the currently-effective 800 Series rate structure with those changes highlighted in Joint Exhibit D.

Mr. Shambo stated the Customer Charge for Rates 611, 612 and 613 would increase to $11.00 per month, consistent with the recently approved gas general base rate case settlement for NIPSCO. The Settling Parties have agreed to a single block rate for energy. Lastly, the Settling Parties have agreed to standardize the breakpoint for a space heating discount to 700 kWh in all of the Rates 611, 612 and 613.

Mr. Shambo stated the Customer Charge for Rates 620, 621 and 622 was changed to $20,with the exception of three phase service to address concerns for low volume commercial customers.

Mr. Shambo stated Rate 625 has been updated and retained and is available for eligible metal melting customers.

Mr. Shambo testified that NIPSCO and the consumer parties have worked since before this proceeding was filed to achieve a rate design and service structure that is satisfactory to all customer classes. He testified that the agreed-to rate design and service structure represent a consensus of all Settling Parties. Specifically, Rates 632, 633 and the addition of 634, along with Riders 675 and 676, are all part of the necessary service structure.

In terms of the specific details for Rate 632, Mr. Shambo explained that this rate is designed to address the needs of lower-load factor, energy intensive customers such as arc furnaces. He stated that when it came time to design rates and implement the agreed-to revenue requirement and allocation, it was apparent that there was a need to grandfather test year customers and/or load migrated to Rate 632. Mr. Shambo explained that Rate 632 was built based upon the assumed load and the Settling Parties have agreed to maintain that foundation. He testified that in order to achieve the agreed-to revenue requirement and allocation while maintaining the features and intent of proposed Rate 632, it became clear that the rate should be available only to customers whose demand is at least 15 MW, but that grandfathering current Rate 832-eligible customers was also necessary and reasonable. The three inclining energy block structure in Rate 632 was specifically designed to maintain the integrity of the relationship between Rates 632 and 633 and avoid unintended migrations of customers. He stated the Settlement continues to apply Riders 675 and 676 to customers under Rate 632.

Mr. Shambo explained that Rate 633 is designed to address the needs of high-load factor customers. He testified that, unlike Rate 632, the Settling Parties are not proposing to increase the minimum demand under Rate 633; instead, it remains at 10 MW. Mr. Shambo stated Rate 633 no longer incorporates hours of energy into the demand charge. Rate 633 incorporates a three declining energy block structure with a smaller demand charge. He stated that the Settlement continues to apply Riders 675 and 676 to customers under Rate 633.

Mr. Shambo testified that Rate 634 is a new rate schedule proposed in the Settlement and it is different from both Rate 632 and Rate 633. He stated that Rate 634 importantly assists in creating greater interruptible capability, provides for operational flexibility and creates the potential for growth in NIPSCO's service territory to the extent it permits the identified customer to increase production of a competitive product at lower marginal cost. He stated that NIPSCO and the identified customer devoted a significant amount of time to develop this rate schedule to help provide for some of the flexibility inherent in the current 800 Series rate structure and special contract while also meeting the objectives in this proceeding. He testified Rate 634 is designed upon the same principles underlying other rates – i.e., upon an allocated revenue requirement and test year determinants, and that the base determinants utilized for the identified customer on Rate 634 are the same as what would be utilized if the customer selected Rate 633. In addition, the allocated revenue requirement is the same as what would be utilized for Rate

633. He explained that the differences rest in the rate structure and are responsive to the specific needs of one of NIPSCO's largest electric customers.

In terms of the specifics of the rate structure for Rate 634, Mr. Shambo testified the notable difference from other large industrial rate schedules is the existence of an overrun energy rate concept. Each hour, the Company will charge the customer an energy rate based upon whether it is above or below its contract demand. He stated that this rate structure allows for a sophisticated, large energy consumer to manage consumption levels around specific breakpoints. He explained that because of this structure and the identified customer's operation, there is no need for surplus or temporary capacity. Moreover, Mr. Shambo stated that the design of the rate structure is based on the fact that the customer will pay a demand charge on a fixed contract demand. The contract demand would only change if the overall average of the customer's on-peak demands exceeds a 12.5% threshold above the existing contract demand. He stated that this provides certainty for both the customer and NIPSCO, and would improve the competiveness of the region for manufacturing.Mr. Shambo explained that the Settling Parties have agreed that NIPSCO should file a petition within two years seeking approval of a revenue neutral transition plan to standard rates for current space heating customers. Mr. Shambo stated the incentive for customers that transition to a natural gas space heating option rather than electric is not being discontinued. He stated that NIPSCO had proposed a one-time incentive of $25 for customers that elected to transition to a natural gas space heating option rather than electric due to the fact that natural gas is more efficient and that the Settlement retains this incentive, and NIPSCO has agreed to provide this incentive from its own funding below-the-line.

(4) Interruptible Rider 675. Mr. Shambo testified Rider 675 balances the needs of all customer groups. He stated that Rider 675 is a key settlement component that is based upon the inputs and compromise from all Settling Parties representing all customer classes. He explained that some of NIPSCO's largest industrial customers are capable of being interrupted, which is beneficial to all customers. He stated that customers willing to guarantee that they will interrupt service on demand, for the benefit of others, should be compensated. He explained that Rider 675 provides these credits to those customers and that the credits are then recovered through the RA and the FAC trackers from all other customers that are receiving the benefit. He stated this is superior to building expected amounts into rates because this mechanism assures that no gap will exist between amounts recovered from customers and the amount of credit provided to industrial customers.

Mr. Shambo testified that Rider 675: (1) caps the overall annual credits to $38 million (in addition to a cap of 500 MW); (2) allows customers with multiple premises to aggregate interruption capability, if they choose Option A, B or C, to help provide customer flexibility; (3) adds a new option; (4) allows market pricing to determine the credits paid under Option A; (5) treats buy-through energy during an Interruption at the Real-Time Locational Marginal Price ("LMP") unless otherwise elected by the customer through prior notice; and (6) includes minimum contract lengths for the various options.

Mr. Shambo testified the interruptible credits are provided for two reasons, reliability and economic, each of which provides value to all customers. He stated that while there is no way to know exactly how much value will result from either, it is clear that reliability is associated with reducing capacity cost and economic will reduce energy costs. He testified the Settling Parties have agreed that 75% of the credits should be recovered through the RA Tracker and the balance through the FAC.

Mr. Shambo explained that reliability is the ability to physically curtail a customer's service in order to maintain system integrity and the credit value is derived from the cost of new capacity. This is beneficial to all customers over time because NIPSCO will be able to avoid purchases of capacity in the market and can delay building new generation capacity. He stated that NIPSCO's current estimated cost of capacity is based on three reference points (1) the price per KW for a new combustion turbine ("CT"), (2) the price per KW for a new combined cycle gas turbine ("CCGT"), and (3) current market price of capacity. He explained that while there exists today a reasonable or excess capacity situation in the broader market, this situation will not continue over time, as environmental laws are likely to take a number of generators off line in the next decade. Mr. Shambo explained that capacity value is a marginal calculation that is likely to be seen in radical terms (very low lows and very high highs) because of the time frame and cost associated with building new generation. Supply change (generating capacity) will move slowly as will demand. Therefore, during periods of clearly excess generation, the price will be low, such as the current market. However, he stated that as capacity becomes tight the price likely will rise sharply. He testified the Settling Parties have distinguished credit pricing based upon the length of contract the customer is willing to sign, and this will help to manage the influence of this radical change on NIPSCO's own supply curve.

Mr. Shambo explained that another distinguishing characteristic of reliability is the ability to change supply / demand. He stated that clearly, quicker responsiveness from resources provides greater value. He explained that newer peaking generation technology can be online and synchronized within 10 to 20 minutes. Most CCGTs can be online within 1 to 4 hours, and the startup time for NIPSCO's existing CTs is roughly one hour. Mr. Shambo stated that MISO rules on load modifying resources require changes within 4 hours. He explained that the interruptible services included as part of the Settlement are also distinguished based upon response time.

Mr. Shambo testified the final distinguishing characteristic is the number of curtailments allowed in a given season. He explained that two of the options follow MISO requirements with limitations on curtailments as opposed to the last two options which are more closely aligned with a physical unit which can start an unlimited number of times.

Mr. Shambo explained that economic interruption is defined separately from reliability events or curtailments. Economic interruptions provide the industrial customer the option to either buy through at market prices or reduce demand. He stated this is beneficial to all customers because it allows NIPSCO to reduce marginally more expensive production (from peaking units) or market purchases, and that these activities generally reduce the cost incurred and recovered through the FAC. He stated the number of economic interruptions allowed in each option is a distinguishing characteristic, where the greater the number, the greater the value.

Mr. Shambo testified that another distinguishing characteristic is the duration of interruption. The greater the duration allowed by the option, the greater the value of that option to customers paying for the credit.

He stated that economic interruptions are triggered by high market prices, which are a function of demand and supply. The major drivers on demand are the general economic state and temperature. He stated that recent events provide some guidance on the value of interruptibility. He explained that NIPSCO has called interruptions on six separate days since May 1, 2011. He stated that while clearly 2011 has been a hot summer, the broader economy has not come close to full recovery. If the economy had fully recovered, the market price per kWh this summer could have been much higher – possibly leading to curtailments.

Mr. Shambo testified reductions in capacity will lead to higher LMPs. He stated that the majority of capacity that will be retired within the near term is coal based and that marginally more expensive production capability will take its place increasing the market price of power, especially if the marginal production is gas based CTs. He explained that if the capacity is not replaced, LMPs could reach very high prices if this is the tool used to bring demand and supply into balance because the marginal value of electricity to most customers far exceeds the costs to produce or the price at which most regulated electric utilities sell power.

Mr. Shambo testified the Settling Parties have agreed to limit availability of Rider 675 for a number of reasons. He explained that there is always some level of uncertainty around how much capacity will be required. Currently, NIPSCO has approximately 200 MW of interruptible resources and has acquired an additional amount of market capacity of 150 MWs.

He explained that the limitation on price is more of a practical limitation to avoid unanticipated consequences. He stated that while the Settling Parties do not know how much interruptible demand participants may provide, establishing a cap of $38 million would allow the Settling Parties to assess the "what if" impact on customers not taking the service.

Mr. Shambo explained the various options and how each option relates to the rationale as follows:

- Option A is a market based product that is only curtailable, not interruptible for economic purposes. This option matches the MISO market place definitions for curtailable capacity and is therefore comparable to short-term capacity bought and sold in the marketplace. Option A has the shortest term contract (1 year), the fewest number of hours curtailable and the greatest limitation in the number of curtailments (5) per summer. Service under Option A is curtailable on 4 hours' notice. The credit is correctly set initially near the market at $1.00. NIPSCO will make a 30-Day Filing to reset this rate every January based upon market prices.

- Option B is one of two middle ground options. The Option B curtailment rules are identical to Option A. The contract term (3 years) is longer than Option A. However, Option B is interruptible for economic reasons. The economic interruptibility is limited, but still significant. Limitations are as follows: one per day, 10 consecutive hours, no more than 2 consecutive days or 3 days in a week and no more than 100 hours per year. The proposed credit of $6.00 for Option B is a function of negotiations but considers both reliability value and economic value.

- Option C is the second middle ground option. The Option C curtailment rules are different from Option B and much more akin to a peaking unit, creating greater value to other customers. Importantly, curtailments are unlimited in number and the notice period is reduced to 1 hour from 4 hours in Options A and B. The contract term (7 years) for Option C is over twice as long as Option B. The economic interruption rules are similar to Option B, with the only difference being the number of consecutive hours of interruptibility is 12 hours versus 10 hours. The proposed credit for Option C is $8.00.

- Option D is the highest value service, providing considerable flexibility for the benefit of all other customers. It is long-term (10 years). There are no constraints on curtailment. Finally, it is curtailable on 10 minutes' notice. Those same rules carry over into economic interruptions, again increasing the value. This service can be economically interrupted up to 3 days per week and 200 hours per year, both considerably greater than Option C. Option D is the closest to the existing Rate 836. For comparison purposes, that rate is currently receiving a credit of approximately $13, considerably more than the $9.00 credit agreed to in this proceeding. The customer currently using Rate 836 has faithfully met every call over the years on this service and has been a welcomed partner.

Mr. Shambo stated it is important to highlight the benefits of Options B, C and D while NIPSCO is also experiencing a summer of intense heat. He explained that the week of July 18 provided the MISO region with a number of consecutive weekdays of heat warnings. It is during this time while businesses and industry work and customers run air conditioners at home that the system sees the greatest amount of stress. He stated the ability to call upon customers to curtail and interrupt with less notice and curtail more often is of benefit to the system and all customers. He stated it is helpful to incent a greater diversity of interruption and curtailment options, not just an economic benefit, but a system reliability benefit that cannot always be measured in dollars per kW. Mr. Shambo testified all of the Rider 675 options provide these benefits, but Options C and D more so.

Mr. Shambo explained that when economic interruptions are called, customers will have the option to "buy-through" into the market. When a customer "buys-through" they will be paying LMP plus an adder. He stated NIPSCO will not be supplying the customer with FAC power during this time; therefore, FAC customers continue to benefit from the bargain.

Mr. Shambo described the allocation of credits if demand exceeds limits (either 500 MW or $38 million annually), as follows.

The Initial Allocation will be as follows:

- First to current interruptible customers up to the amounts in their current agreements. NIPSCO currently has two contracts with interruptible provisions.

- Second to customers under an "open season." Initially, all eligible customers not receiving special pricing or credits at the time new rates go into effect, will make requests for interruptible credits. Customers have the option to exit any such agreement in order to qualify. The effectiveness of the credits would be applied when new rates are implemented. If demand exceeds limits (either 500 MW or $38 million annually) the interruptible credits will be distributed based upon the value of the interruptible credit with the highest demand credit value allocated first.

Allocation will be in 1 MW increments (rounded up). Therefore, if a customer has requested the minimum 1 MW, but the allocation process yields less than that, they will still be allocated 1 MW and other customer volume will be rounded down to stay within the cap.

For future periods, NIPSCO will take requests for any available interruptible credits beginning January 15 and no later than February 1 of each year. NIPSCO will assess availability, allocate interruptible credits based upon the procedures above and provide notice to customers by March 1.

Mr. Shambo stated that while contracts have minimum lengths in accordance with the tariff, a contract expires automatically when new rates (base or interruptible credit) take effect.

In response to questioning from the Presiding Officers, Mr. Shambo explained the impact on residential customer bills from the interruptible credits, assuming full subscription under Rider 675. The same typical residential customer using 688 kWh per month discussed previously would see an additional $2.35 per month. See Petitioner's Exhibit No. 1-S, IURC Set 2-002 Attachment A, page 2 of 2. He explained that full subscription of $38 million is close to double the level which would arise from the current interruptible customers. He further explained that there is a lag between interruptible contract execution and the 6-month RA Tracker filing, and that by the time any material level of interruptible credits would be reflected, the increase would be offset significantly by the "zeroing out" of the currently effective EERM (which would account for $1.42 of this hypothetical customer's monthly bill).

(5) Rider 676. Mr. Shambo explained that Rider 676 provides back-up, maintenance and temporary power to industrial customers served under Rates 632 and 633. These services are provided to industrial customers because the process of converting raw materials into other products is fraught with potential production uncertainties related to the equipment used in the process. He explained that equipment failures can and do occur in the industrial process and that routine maintenance can lessen the risk of an unexpected upset; however, changes in demand for electricity can and will occur due to unexpected non-routine events. He stated that Rider 676 is a relief valve to avoid demand ratchets due to these events.

Mr. Shambo testified NIPSCO has two primary rules embedded in Rider 676. First, the facility must truly be a cogeneration unit, not simply a peaking unit fired to lower demand. Second, the unit must be maintained in a fashion that the outages, covered by back-up, on an annual basis are limited to 45 days. He testified back-up service is for unplanned outages and maintenance service is for planned outages. He explained that the back-up rate is designed to avoid cost shifts to FAC customers due to unexpected load on NIPSCO's system. He stated the rate paid for back-up is a daily demand charge plus LMP plus a non-fuel energy charge of $.0035 per kWh, which is beneficial to the customer in that it does not increase its billing demand due to an unexpected increase caused by equipment failure. Mr. Shambo testified this is reasonable to NIPSCO because the adder does cover variable operating costs and contributes to fixed costs.

Mr. Shambo explained maintenance service is different from back-up service in a few significant ways. First, this service is for planned maintenance of behind the fence generation. Second, maintenance is not available during the summer, whichfurther encourages usage in the off-peak months of February, March, April and October. Third, because maintenance is planned service, the pricing is based on the FAC plus the energy charge in Rate 632 or 633, whichever is applicable. Mr. Shambo stated this service includes a demand charge of \$0.44 per kW per day during the moderately high demand months of December, January and May or \$0.25 per kW per day in the months of February, March, April and October. He explained that as with back-up service, maintenance is curtailable, but not interruptible for economic reasons once it has been granted. Once the service is granted, the customer pays a minimum of 80% of that granted. He stated the service is available for up to 60 days per year per customer.

Mr. Shambo explained how temporary service is different from back-up and maintenance service. He explained that NIPSCO's original filing had only a temporary service designed to cover all unexpected needs for industrial customers. He stated that temporary service continues to be a catch-all for everything from spikes in demand to non-cogeneration equipment failure. For example, this service encourages a customer to take on a marginal order that otherwise might be avoided in order to manage the demand billing determinants to an ongoing run rate level.

Mr. Shambo stated the daily demand rate increases as the number of days increase. He explained that while NIPSCO wants to accommodate incremental projects, if baseline demand is increasing demand billing units should also increase within any rolling 12 month period. He explained that unlike back-up or maintenance, NIPSCO can deny temporary service for economic reasons. However, customers have a "buy-through" option similar to Rider 675. He explained that temporary power can only be interrupted to the extent Rider 675 has previously been interrupted. This higher priority is due to the fact that temporary service under Rider 676 has a daily demand charge.

(6) Discussion of Reasonable Return. Mr. Shambo testified that while the agreed-to ROE of 10.2% is higher than that approved in the 43526 Order (9.9%), it is lower than other comparable electric investor-owned utilities ("IOUs") in Indiana. He noted that Vectren's recent base rate case order approved a rate of return on equity of 10.4%; I&M's (approved 3 years ago) is 10.5%, and Duke's is 10.5%. The ROE is within the range identified in the 43526 Order of 9.9% to 10.5%.

Mr. Shambo stated that as to the agreed-to rate of return of 6.98%, it is lower than the comparable electric IOUs in Indiana. He noted that Vectren's is 7.29%, I&M's is 7.62% and Duke's is 7.30%. He testified that the resulting net operating income of \$188.9 million is an acceptable return on the fair value of NIPSCO's utility plant in service.

Mr. Shambo testified the increase in NIPSCO's ROE relative to the 43526 Order is appropriate because of NIPSCO's service improvements. Pointing to NIPSCO's case-in-chief, Mr. Shambo testified NIPSCO has improved key service metrics for the benefit of customers, including its equivalent forced outage rate ("EFOR"), customer average interruption duration index ("CAIDI"), system average interruption duration index ("SAIDI") and customer perception scores. He stated these improvements all support the agreed-to ROE and also support how NIPSCO needs to remain financially stable to support further investments to provide reasonably adequate service and facilities and to invest in infrastructure to support the local region and jobs and growth.

Mr. Shambo testified that the Settling Parties have agreed to reset the bank of under-earnings calculated according to Ind. Code § 8-1-2-42.3 to $200,000,000. He stated that since its last implemented electric rate case, NIPSCO has amassed more than $1.8 billion in cumulative under-earnings. He explained that in settling the overall issues in this proceeding, the Settling Parties have agreed that $200,000,000 is a reasonable starting point for purposes of the earnings bank calculation upon the implementation of new electric base rates and charges.

(7) Settlement is in the Public Interest. Mr. Shambo testified the Settlement represents a diligent effort by all Settling Parties to reach a comprehensive result. He stated the complexity of the issues and the diversity of the Settling Parties dictated the need for compromise on the part of everyone involved, and the Settlement reflects a delicate balance that accommodates the interests of all Settling Parties in a reasonable way.

Mr. Shambo testified that approval of the Settlement is consistent with the public interest. He noted that in reaching agreement in this case, the Settling Parties have attempted to take previous Commission decisions into account, including the 43526 Order. He opined that the fact that the Settling Parties were able to negotiate a settlement in this proceeding representing all customer segments and diverse interests is strong additional evidence that the Settlement is in the public interest. He also added that the ability to obtain a Commission decision in a more timely and cost effective manner, coupled with certainty about the terms and conditions which have been negotiated, is of the utmost importance in the settlement context. He stated that without such certainty, settlements may not be reached. He testified that the Settlement provides that if following its examination, the Commission finds the Settlement to be in the public interest, the Settlement should be approved in its entirety and without change or condition(s) unacceptable to any Settling Party.

Mr. Shambo testified the Settlement represents a comprehensive resolution of all of the issues in this proceeding and Cause No. 43526. The Settlement resolves complex, divisive, and controversial issues surrounding revenue requirement, revenue allocation, rate design and a number of issues that the parties have been litigating for a number of years. In addition, the Settlement balances the interests of NIPSCO with those of its customers without the expense and risk of continued litigation and potential appeal. He stated the Settlement provides NIPSCO with an opportunity to earn a reasonable return on the investment it has made, balanced with the interests of NIPSCO's customers in receiving reasonable service at a fair cost.

Mr. Shambo explained that time is of the essence and the Settling Parties have agreed to request that the Commission review the Settlement on an expedited basis. He explained that this would finalize years of litigation related to these issues and send a signal of finality and certainty to NIPSCO's customers and the financial marketplace regarding NIPSCO's electric basic rates and service structure.

(b) Linda E. Miller. Ms. Miller addressed each of the revenue requirement settlement changes from NIPSCO's proposal in its filed case-in-chief. She also briefly described the process that will be used to perform a final reconciliation of the customer credits that NIPSCO has been providing to customers in accordance with the Commission's September 23, 2002 Order in Cause No. 41746 ("41746 Order").

Ms. Miller testified that the Settlement modifies NIPSCO's original request and now proposes a gross revenue amount of $1,401,000,000, which reflects a revenue increase of $6,853,718 as compared to test year pro forma results based on current rates. She stated that gross margin requirement is $926,541,944. After adjusting for non-trackable fuel, other revenues and the credit related to emissions allowances, the Settlement provides for approval of base rates to recover revenue of $1,355 million and gross margin of $909 million. Ms. Miller testified this will provide the opportunity to earn net operating income of $188,872,242. She stated the settlement revenue requirement of $1,401,000,000 reflects a reduction of $68,886,481 from the original request of $1,469,886,481 in NIPSCO's filed case-in-chief.

Ms. Miller testified that Joint Exhibit B is the Statement of Operating Income for the twelve months ended June 30, 2010 shown on an actual basis, with pro forma adjustments at current and proposed settlement rates. She testified that during the course of the settlement discussions, several expense adjustments were agreed to, which result in differences between the Company's originally filed case and the amounts in the Settlement. Each of the adjustments was discussed in Ms. Miller's settlement testimony. She stated that the settlement adjustments consist of (1) adjustments that reflect new line items that were not shown in the exhibits in the Company's case-in-chief and (2) changes to the amounts of line items that were reflected as adjustments in the Company's case-in-chief. Column I of Joint Exhibit B reflects the settlement adjustments and Column J reflects the settlement pro forma results at proposed rates.

Ms. Miller testified that Petitioner's Exhibit No. LEM-S5 shows the computation of the overall weighted cost of capital for NIPSCO. She stated the only changes to this exhibit from that filed in NIPSCO's case-in-chief are to reflect the settlement return on equity percentage of 10.2% and the resulting overall weighted average cost of capital of 6.98%.

Ms. Miller testified that per the terms of the Settlement, upon the effective date of new rates following the issuance of a Final Order in this proceeding, the customer credit approved in the 41746 Order will cease. She stated that after reconciliations of the revenue credit have been performed for all billed months, the final balance of any over or under credit will be included in the variance in the FAC filing that follows the final revenue credit reconciliation month.

(c) Curt A. Westerhausen. Mr. Westerhausen described NIPSCO's proposed IURC Electric Service Tariff, Original Volume No. 12, including the Rates, Riders and Rules (the "Settlement Tariff," attached to Mr. Westerhausen's testimony in support of the Settlement as Petitioner's Exhibit No. CAW-S2). He also explained how the Settlement Tariff differs from the Proposed Tariff (the tariff originally proposed in Petitioner's case-in-chief). Mr. Westerhausen testified the rates and charges were revised consistent with the agreed-to base rate revenue of $1,355 million and class allocations contained within the Settlement. He provided a summary, in general terms only, of changes to the Rates and Riders. For Rates 611, 612 and 613, (1) the Customer Charge was reduced to $11.00; (2) the declining block energy structure was replaced with a single block energy rate; and (3) the space heating/heat pump rates have been standardized to all start at 700 kWh during the space heating season. For Rates 620 and 622, the Customer Charge was reduced to $20.00 to match the commercial Customer Charge in Rate 621. For Rate 621, (1) the Customer Charge was reduced to $20.00; (2) the declining block energy structure was replaced with a single block energy rate; and (3) the Minimum Monthly Charge was changed to include a $34.00 Minimum Monthly Charge for three-phase service. For Rate 624, clarifying language was added such that contracts that have extended beyond the initial term would terminate at the end of any calendar month thereafter. For Rate 625, the hours of service have been modified to include an 8 hour on-peak window, and the customer can choose on an annual basis which five consecutive hours to designate as on-peak and the remaining three hours will be considered as off-peak hours. For Rate 626, clarifying language was added such that contracts that have extended beyond the initial term would terminate at the end of any calendar month thereafter.

Mr. Westerhausen testified that for Rate 632, (1) the minimum contract capacity requirement for new customers was increased to 15,000 kilowatts; (2) facilities being served under Rate 832 on June 30, 2010; facilities which would have been eligible for Rate 832 on June 30, 2010 but for being on a Special Contract or on Rate 845; or facilities that would have been eligible for Rate 832 on June 30, 2010, which are located behind the meter of a facility eligible under Rate 632, were grandfathered into Rate 632 and those facilities remain eligible for Rate 632 regardless of any change in name, or ownership, or operation of those facilities; (3) the two tiered demand rate has been collapsed into a single block demand charge; (4) the two tiered energy rate has been modified into a three tiered inclining block energy rate; (5) clarification language was added in determining the billing demand that the customer's half hour demands would be reduced for any back-up, maintenance and temporary service utilized during the month before determining the maximum on-peak and off-peak demands; (6) Surplus Capacity allotted by the Company will not exceed 15% of the Contract Demand; and (7) clarifying language was added such that contracts that have extended beyond the initial term would terminate at the end of any calendar month thereafter.

Mr. Westerhausen summarized the changes to Rate 633 as follows: (1) modified to remove all energy from the demand charge; (2) the energy structure is a three tier declining block structure; (3) in the original filing, the first 600 hours of energy was included in the demand charge; now the first 600 hours of energy are in the first energy block; (4) clarification language was added in determining the billing demand that the customer's half hour demands would be reduced for any back-up, maintenance and temporary service utilized during the month before determining the maximum on-peak and off-peak demands; (5) Surplus Capacity allotted by the Company will not exceed 15% of the Contract Demand; and (6) clarifying language has been added such that contracts that have extended beyond the initial term would terminate at the end of any calendar month thereafter.

Mr. Westerhausen explained that Rate 634 is a new rate schedule available to air separation and hydrogen production market customers with a contract minimum of 150 MWs, including aggregation of multiple delivery points to facilitate interruption of load. Customers are required to contract for at least 40 percent of their load as interruptible in accordance with Option D under Rider 675. A Demand Charge is assessed on Contract Demand. There are three block Energy Charges based upon kilowatt hours used. The first block is for all energy on an hourly basis under the Contract Demand, the second block is for all energy on an hourly basis between Contract Demand and 225,000 kilowatts, and the third block is for all energy on an hourly basis over 225,000 kilowatts. Determination of Contract Demand is based upon the Customer's average on-peak demands and is adjusted annually when the average on-peak demands vary by more than 12.5% of the current Contract Demand.

Mr. Westerhausen explained that Rider 670 was modified to include recovery of 25% of costs associated with credits paid for interruptible load. Rider 674 was modified to include recovery of 75% of costs associated with credits paid for interruptible load. Rider 675 was modified to include customers taking service under Rate 634. Rider 675 has a total capacity limit of 500 MW and a total sum of demand credits availability of $38,000,000 in any calendar year.

Mr. Westerhausen testified that Rider 676 was modified to include back-up and maintenance services. Back-up service is available to customers with verified internal electric generation fueled with energy sources such as, but not limited to, process off-gas or waste heat, natural gas, oil, propane, coal and coal by-products and that is capable of meeting the efficiency standards established for a cogeneration facility by the Federal Energy Regulatory Commission ("FERC") under 16 U.S.C. 824a-3, in effect November 9, 1978 ("Cogeneration Systems"). The Customer may request (including on a pre-qualifying basis) back-up service that may only be available for up to 45 calendar days per Cogeneration System per 12 rolling months. Eligibility for back-up service requires a contract between the customer and the Company that includes information on the Cogeneration System(s). The customer provides initial notice of its request for back-up service within 60 minutes of an event. Back-up service is billed on a daily Demand Charge based on the customer's applicable Rate 632 or 633 Demand Charge divided by the number of days in the month. All kilowatt hours used for back-up service is subject to an Energy Charge equal to Real-Time LMP plus a non-fuel charge of $0.0035 per kWh. A buy-through provision was added to temporary service. To the extent a customer requests temporary service and the Company denies such a request under this Rider, the customer may elect to buy-through subject to an Energy Charge equal to Real-Time LMP plus a non-fuel energy charge of $0.0035 per kWh. The Customer may not elect to buy-through under this Rider if the Company has initiated a curtailment(s) on its system. The Company has the right to deny a request for temporary service if Day Ahead LMPs exceed the Company's current Commission-approved Purchased Power Benchmark that is utilized to develop the Company's fuel cost charge under Rider 670.

Finally, Mr. Westerhausen testified that Rider 677 was modified to include a new eligibility threshold requirement of a minimum of ten (10) full-time equivalent jobs created per project.

Mr. Westerhausen testified the Settling Parties are not proposing any changes to the Purchased Power Benchmark approved in the 43526 Order. He stated that since the Purchased Power Benchmark is being used to trigger economic interruptions of NIPSCO's industrial customers, NIPSCO will make available to its industrial customers who have signed-up for Rider 675, NIPSCO's best estimates of the daily Benchmark as soon as it is available to NIPSCO for the customers' planning purposes.

Mr. Westerhausen also testified that for purposes of Rider 671 (Adjustment of Charges for Regional Transmission Organization) and Rider 674 (Adjustment of Charges for Resource Adequacy), the Settling Parties agreed to utilize the demand allocators set forth in Table 1 of Joint Exhibit E to the Settlement. He stated the demand allocators for purposes of the RA Rider will be based on those set forth in Joint Exhibit E and modified to reflect the amount of interruptible load contained in Rates 632, 633 and 634. At the hearing held in this Cause, Mr. Westerhausen testified that the parties had not specifically stated in the Settlement that the Production Energy Allocation variable in Rider 671 was based upon the percentage allocation of energy used during the test year by the various rate classes. He also explained that the parties had not reached an agreement regarding the allocation of the costs in Rider 672 and 673. He stated that the Settlement does not preclude the Commission from deciding the proper allocation for these two Riders in a subsequent proceeding.

Mr. Westerhausen testified that the Settlement Tariff also reflects the following Rates and Riders that had been approved since the filing of the Original Tariff: (1) Rate 665 – Feed-In Tariff was approved in Cause No. 43922; (2) Rider 681 – Demand Response Resource Type 1 (DRR 1) – Energy Only and Rider 682 – Emergency Demand Response Resource (EDR) – Energy Only were approved in Cause No. 43566; and (3) Rider 683 – Demand Side Management Adjustment Factor ("DSMA") and Appendix G – Demand Side Management Adjustment Mechanism Factor were approved in Cause No. 43912. He stated that the DSMA also is modified to correct a clerical error that omitted Rate 625 from the applicability section. He noted that all of these additional Rates and Riders were reviewed and revisions were made to implement the tariff layout presented in the 600 Series (i.e., the approved tariff may have referred to language in a rule that is now located in a rate or rider) and any additional corrections noted were made.

Mr. Westerhausen also provided a summary of specific changes to the proposed Rules as follows:

1. Rule 1.2 was revised to remove the reference to a current customer changing to an existing Rate Schedule.

2. Rule 2.1 was modified to state that a copy of the Tariff would be posted on the Company's website.

3. Rule 6.1 governing non-standard service extensions has been modified to incorporate language consistent with that contained in Rule 6.3, which was approved by the Commission as part of the settlement in Cause No. 43706. Rule 6.2 was revised to provide a methodology for service extensions and modification for Transmission and Subtransmission Customers.

4. Rule 7.2 was modified to refer to Rider 679 – Interconnection Standards Rider.

5. Rule 8.1 was modified to clarify that the cost of necessary repairs or replacements shall be paid by the Customer if Company property is destroyed due to Customer's violation of applicable tariffs. Rule 8.5 was revised to insert that an unauthorized user would be responsible for paying out-of-pocket costs for repairs.

Rule 8.6 was revised to provide that the Customer has the right to challenge the Company's determination that it is required or appropriate for the Customer to comply with the standards of outside agencies or duly applicable organizations including FERC, North American Electric Reliability Corporation ("NERC"), Reliability*First*, and MISO.

6. Rule 10.2 was submitted as Joint Exhibit H to the Settlement. It was modified to define the equitable non-discriminatory manner that the Company will use to determine the creditworthiness of both a Customer and an Applicant. As a guarantee against the non-payment of bills, a deposit payable in cash or by letter of credit in an amount equal to the Customer's two (2) highest months usage based upon the most recent twelve (12) months historical usage or two months of projected usage for an Applicant. For Customers with multiple accounts, each account will be treated individually for purposes of this Rule. In the case of a cash deposit as a guarantee against the payment of bills, simple interest thereon at the rate established by the Commission will be paid by the Company for the time such deposit is held by the Company. Upon discontinuance of service, the amount of the final bill will be deducted from the sum of the deposit and interest due, and the balance, if any, will be remitted to the depositor.

7. Rule 12.3 was revised to require the Company to provide no less than 14 days written notice to non-residential customers prior to disconnecting the Customer's service. Rule 12.3.2 was modified to replace the "Customer's failure to allow access" with "Customer's denial of access".

8. Rule 13.2 was revised to modify the calculation for the amount the Demand Charge is reduced because of any disruption, suspension, Reduction or Curtailment of the delivery of Energy, unless due to the fault, neglect or culpability on the part of the Company. For reductions or Curtailments of electric Energy below Customer's Billing Demand, the Demand Charge will be reduced by the amount of the number of kilowatts reduced or Curtailed multiplied by the ratio of the number of hours in which the Curtailment was in force to the total number of hours for the billing period in which the Curtailment was in force.

Mr. Westerhausen also provided a summary of the changes to the Standard Contract originally included in NIPSCO's case-in-chief. He stated that the title of the Standard Contract was revised to show that it also applies to Rate 634 and Rider 676; under Rider 675 Demands, there were four options (Options A, B, C and D) added for the Customer to designate the quantities of Interruptible Contract Demand; a new section for Rider 676 Back-up Service, was added to (1) describe the information to be provided by the Customer to qualify for Back-up Service and (2) describe the requirements for adequate metering or submetering of Cogeneration Systems; and under Paragraph 4, Terms and Conditions, a reference to Commission approval of charges under the contract was added.

Mr. Westerhausen sponsored Revised Petitioner's Exhibit No. CAW-S4, which is a revenue proof incorporating the agreed-to revenue requirement and the modifications in the Rates and Riders.

(d) John J. Spanos. Mr. Spanos supported the Settlement's modifications to the depreciation rates for NIPSCO's electric and common plant as of June 30, 2010 which he recommended in NIPSCO's case-in-chief. He sponsored Petitioner's Exhibit No. JJS-S2 showing the results of his Depreciation Study, as modified to reflect the changes provided by the Settlement.

Mr. Spanos testified the updated pro forma depreciation expense is $4,905,389 less than the original study would have produced. He testified the updated rates are based on the same methods and procedures used in the original study. He stated the only changes relate to net salvage percents for steam production, station equipment and distribution poles. He noted that the calculation of appropriate depreciation accrual rates involves, among other things, the application of informed engineering judgment. He testified the modifications to the accounts are minor and are reasonable in the exercise of that informed engineering judgment and, as a result, he supports them.

B. OUCC's Evidence in Support of Settlement. Tyler E. Bolinger, Director of the Electric Division for OUCC provided testimony in support of the Settlement. Mr. Bolinger testified that, if approved, the Settlement would bring to an end three years of litigation and provide certainty around critical issues, including revenue requirements, authorized return, the earnings bank, and the allocation of revenue requirements among NIPSCO's various rate classes. He stated that the Settlement provides a reasonable balance between utility and ratepayer interests, and provides for the establishment of new base rates for NIPSCO retail electric service for the first time since 1987. Mr. Bolinger explained that the general preference for settlement over litigation is particularly appropriate given the challenges faced in a NIPSCO base electric case. He noted several of the unique challenges presented in this case, including:

- NIPSCO's existing base rates are nearly 25 years old.
- Few, if any, NIPSCO electric ratepayers actually paid NIPSCO's full tariffed rates during the entire test year in this Cause. Thus, evaluation of existing rates is complicated by the need to account for the numerous discounts and credits that customers have received.
- NIPSCO has decided to move away from special contracts with Industrial customers; many Industrial customers were faced with the prospect of both the loss of contract discounts and a move back to increased tariffed rates.
- NIPSCO's service territory is a major global manufacturing center with numerous customers competing in global markets.
- As a global manufacturing center, NIPSCO's territory has been hard hit by the severe global recession, with many persons suffering unemployment and poverty.

- NIPSCO has extraordinary diversity in its customer base, which goes beyond the usual differences between large and small users. *Id.* pp. 4-5.

Mr. Bolinger concluded that absent the Settlement, the Commission (and likely the Courts) would have to grapple with these challenges for an extended period of time, perhaps a number of years of litigation. He described the balance in the Settlement as "delicate," and strongly recommended approval. He supported the Settlement's proposed revenue requirement and emphasized that the Settlement finally brings about a clear resolution of the contentious issue of allocating the revenue requirement between the various rate classes. He testified that the certainty of a mutually agreeable revenue allocation is a major benefit of the Settlement from OUCC's perspective.

Mr. Bolinger testified that Rider 675 (Interruptible Industrial Service) is a key part of the "delicate balance" in the Settlement. He indicated that OUCC supports Rider 675 as a reasonable part of the Settlement. He explained that interruptible service options enable customers to create value for the overall system by agreeing to interruptions to enhance reliability and/or to reduce the need for the utility to purchase energy in the market at times of scarcity and relatively high market prices. This should over time enable the utility to avoid both capacity and purchased energy costs. He also explained OUCC's position that it is reasonable to consider the fact that some customers have made significant investments to enable interruption of their production processes on very short notice.

Mr. Bolinger concluded by summarizing the many benefits of the Settlement and noting that the Settlement "...moves NIPSCO away from the *status quo* of decades-old base rates combined with an amalgamation of special contract discounts and rate credits. This move toward the transparent provision of service through tariffed rates is appropriate for a utility operating in a fully regulated retail electric jurisdiction."

C. Industrial Group's Evidence in Support of Settlement. Industrial Group presented the testimony of Nicholas Phillips, Jr. and James R. Dauphinais, consultants with the firm of Brubaker & Associates, Inc.

(a) Nicholas Phillips, Jr. Mr. Phillips testified regarding the ratemaking and policy issues involved with the Settlement. He recommended approval of the Settlement because it is based on appropriate regulatory policy and sound ratemaking principles. He explained the Settlement is a comprehensive agreement that resolves both revenue and the complex allocation and rate design issues, including the precipitous industrial sales decline due to the economic slowdown, the extraordinary length of time since new base rates were implemented, the proposed elimination of various rates and the expiration of special contracts. He added that the Settlement also terminates issues from NIPSCO's 2008 electric rate case in Cause No. 43526 ("2008 Rate Case") and supersedes other provisions of the 43526 Order. Mr. Phillips stated the Settlement should be approved for the following reasons:

1. The Settlement is fair, reasonable and in the public interest;

2. The Settlement mitigates the increase to the residential class and results in a lower percentage increase to the residential class when compared to the increase resulting from the 43526 Order;

3. The Settlement contains an array of industrial rate offerings that collectively provide a reasonable opportunity for NIPSCO's large customers that are subject to global competition to manage power costs and remain a viable and necessary segment of the Northwest Indiana economy;

4. The Settlement eliminates any rate increase for municipalities that use NIPSCO's street and traffic lighting rate schedules; and

5. The Settlement is forward looking, and in his opinion, should lessen the need for another NIPSCO base rate filing in the near future.

(1) Background of NIPSCO's existing rates and charges. Mr. Phillips provided an overview of the relevant background associated with NIPSCO's rates and charges. He testified NIPSCO's current base rates were established by Order in Cause No. 38045 on July 15, 1987, or 24 years ago and included an interruptible rate. He said NIPSCO has been offering some type of interruptible rate for over 25 years and since the Order in Cause No. 38045, NIPSCO has implemented other rates and charges, including Rate 845 and Rider 846 (real time rates which are non-firm) to offer competitive rate options to its large industrial customers. During the hearing Mr. Phillips testified that in the past NIPSCO has had as much as 600 MWs of interruptible service under Rates 836 and 845. NIPSCO also offered special contract pricing options, which arose out of numerous situations. Mr. Phillips added that many of NIPSCO's industrial customers have or are capable of obtaining customer-owned generating facilities as an alternative to purchasing power from NIPSCO. He noted NIPSCO added Sugar Creek to increase the capacity of its generating portfolio in 2008.

Mr. Phillips also provided a brief background regarding NIPSCO's 2008 Rate Case. He explained that under a settlement agreement in Cause No. 42824, NIPSCO was required to file a base rate case using a 2007 test year by July 2008. Although the Commission issued an Order in Cause No. 43526 on August 25, 2010, the rates approved in that Order have not been implemented, and in a docket entry issued on April 25, 2011, the Commission stayed any further action on the 2008 Rate Case until after an Order in this case. Mr. Phillips added that there were numerous difficulties associated with the compliance rates in Cause No. 43526 including a large residential increase and issues with firm and interruptible industrial rates.

(2) Importance of NIPSCO's industrial customers. Mr. Phillips described the importance of NIPSCO's large industrial customers to the economic viability of both NIPSCO and the NIPSCO service area. He testified that NIPSCO's large industrial customers make up a substantial percentage of NIPSCO's electric load. He added the members of the Industrial Group employ over 18,000 people, not including contractors and others who derive employment from serving Industrial Group member companies and facilities, which results in extensive indirect employment from large industrials. As such, the members of the

Industrial Group are some of the largest employers in the NIPSCO service area and their economic viability has a ripple effect on NIPSCO's commercial and residential customers as well. Mr. Phillips explained that many of the smaller industrial and commercial businesses in NIPSCO's service area are dependent on the viability of NIPSCO's large industrial customers. He said a downturn in the productivity of NIPSCO's large industrial customers has a negative impact on NIPSCO's overall revenues and a downturn in their production also has a significant impact on the unemployment rate in Northwest Indiana and the economic viability of smaller industries and businesses. He said these large customers compete not only nationally but globally for business and sometimes even within their own corporate structure as to other plant locations for the companies. He testified that keeping the large industrial customers' operating costs competitive in Northwest Indiana is vital to keeping the existing customers there and attracting new industry.

(3) Reasonableness of the Settlement. Mr. Phillips said the Settlement resolves the complex issues in this case and provides for the conclusion of the 2008 Rate Case in a reasonable manner and serves the public interest. He testified that absent the Settlement, the Industrial Group would have presented testimony on revenue requirement, cost of service and revenue allocation, rate design and NIPSCO's proposed rules. He emphasized that the Settlement was a result of lengthy and arms-length negotiations between the Settling Parties in order to reach a comprehensive settlement and the Settlement was within the range of outcomes that might reasonably be expected if the case had been fully litigated.

Mr. Phillips explained how the Settlement addresses the needs of NIPSCO's large industrial customers. He noted the Settlement results in an increase in rates for NIPSCO's largest customer classes (632, 633 and 634) of more than 20%, but that the overall settlement package provides tools to allow the large customers to try to mitigate the increased cost. He said both Riders 675 and 676 provide options to allow some of NIPSCO's largest customers to mitigate the increased cost. He explained Rider 675 allows NIPSCO's large customers to assess the level of risk that they are willing to take in receiving non-firm service in exchange for demand credits while, at the same time, increasing the options for interruptible service provides additional flexibility to NIPSCO in managing its capacity needs, resulting in savings to all customers. He said Rider 676 provides back-up, maintenance and temporary service to allow those customers with their own generation to efficiently rely on it, again reducing demand on NIPSCO's system.

Mr. Phillips also described the revenue allocation to classes under the Settlement. He testified the basic starting point of the revenue allocation to classes was an across-the-board approach but modified for various rate class mitigation. He noted an across-the-board approach was proposed by NIPSCO in its case-in-chief filing after large industrial customers were migrated to full firm tariffs.

Mr. Phillips explained that the basis of an across-the-board approach is to allocate an even percent revenue increase to all customer classes, rather than an allocation method based on a cost of service study, and that an across-the-board approach basically preserves existing rate relationships. He added that in some cases mitigation is appropriate to prevent rate shock for some customer classes. He said with regard to NIPSCO's case, the unique facts and circumstances made the use of actual test year load data, which were distorted by the impacts of the most severe recession in a generation, challenging in any cost of service study proposed.

He explained that the information required for the cost of service studies NIPSCO presented, and that would have been presented by the Industrial Group if litigation had continued, was subject to the uncertainties associated with customers operating during a severe recession and from customers operating on rate schedules that were being eliminated or contracts that have or will expire. As an example, he said load data at time of one-hour monthly system peaks during the test year may be based on abnormal data due to the severe economic downturn. He explained another problem is that customers on Rate 845, Rate 836 or a special contract during the test year were migrated to a firm rate under NIPSCO's proposed rate structure and it is difficult to estimate or assume exactly how a customer being migrated from a non-firm rate or special contract would operate under a different rate schedule with different price signals. He added that as in the 2008 Rate Case, NIPSCO had to make various assumptions in migrating special contract customers' loads during the test year to existing tariffs. NIPSCO had to make additional assumptions in migrating those customers' loads currently on Rates 836 and 845, or customers who would have migrated to those rates, to firm rates. He said these various factors created obstacles for any cost of service study. Mr. Phillips testified that although NIPSCO performed various cost of service studies with various sensitivity analyses, the sensitivity analyses were not all inclusive.

With regard to interruptible service, Mr. Phillips testified that customers opting for interruptible options have previously received a credit to firm load for allocation purposes. In this case, NIPSCO proposed to eliminate any interruptible rate schedules and move all customers to firm rates. Consequently, the allocation of credits for interruptible service was not part of NIPSCO's filed cost study. Instead, Mr. Phillips noted that the interruptible service options were being offered through Rider 675. For all of these reasons, Mr. Phillips testified that the Settling Parties utilized an across-the-board approach modified for residential mitigation and other considerations to achieve the revenue allocation and resulting rate increase to classes.

Mr. Phillips testified that the revenue allocation resulting from the Settlement is reasonable in his opinion. He said that, as NIPSCO stated in its case-in-chief, a driving factor for its proposal in this case was to help mitigate the impact on the residential class that would have resulted from implementation of the rates approved in Cause No. 43526. He indicated that concern was also a primary goal in the settlement negotiations and ultimate Settlement.

Mr. Phillips also testified that in his opinion, the rate design agreed to in the Settlement is reasonable. He said that to resolve certain rate design issues that existed in the 2008 Rate Case, NIPSCO utilized the current 800 Series rate structures as guides in this case instead of the completely new rate structure concept that caused many concerns and unexpected levels of increase to some customers in the 2008 Rate Case. He said maintaining the current 800 Series rate structures, with some modifications, avoids the concerns and unexpected results to some customers that existed in the 2008 Rate Case. He testified NIPSCO and the members of the Industrial Group were able to work constructively together to arrive at a rate design that achieved both NIPSCO's revenue requirements and the customers' operating concerns.

Turning to particular rates, Mr. Phillips explained that Rate 625 maintains the basic current structure in Rate 825, which the metal melting customers have operated under for over 20 years. Mr. Phillips also said those members currently on Rate 832 and those likely to move to Rate 632 from special contracts along with current Rate 833 customers and those who will ultimately migrate to Rate 633 were actively involved in the rate design changes for these rates that are part of the Settlement. Specifically, the rate design for Rates 632 and 633 were explicitly designed to work with Riders 675 and 676 to allow those customers to mitigate the impacts of the increase resulting from this rate case to those rate classes and also to provide operating flexibility. The Settlement also maintains the high load factor industrial rate and a lower load factor industrial rate which are present in the 800 Series rates. He explained that the new Rate 634 was also a collaborative effort between NIPSCO and the customer qualifying for that rate to address that customer's unique operations and also is designed to work with Option D in Rider 675.

He testified that while Rate 845, Rider 846 and Rate 836 were being eliminated, the new interruptible rider was being offered in the place of those rate structures. In his opinion, the interruptible rate structure in the Settlement should gain customer acceptance and lessen the need for additional generation on the NIPSCO system in the near future. Mr. Phillips testified the Settlement comprehensively addresses temporary power, back-up and maintenance power, which issues were not fully addressed in the 43526 Order.

He said that while a rate increase to industrial customers is difficult in this economic climate, the rate offerings in the Settlement provide a reasonable opportunity for customers to remain competitive in the global marketplace and remain as a necessary ingredient to the Northwest Indiana economy.

Mr. Phillips added that the Settlement also addresses the ongoing dispute between NIPSCO and the Industrial Group regarding the deposit rule for non-residential customers. He said this issue was raised in the 2008 Rate Case and has also remained unresolved in NIPSCO's gas rate case proceeding. He testified NIPSCO and the Industrial Group were able to reach a consensus on the objective, non-discriminatory criteria for requiring a deposit from an existing non-residential customer and also from a new customer. He added the Industrial Group and NIPSCO were able to reach agreement on other changes to some of NIPSCO's proposed general rules and the standard contract which would have been at issue if this case had been fully litigated.

Mr. Phillips concluded that the Settlement, when taken as a complete package, reasonably resolves the Industrial Group's issues in this rate case and results in a fair and reasonable resolution for all of NIPSCO's customers. He said the Settlement provides for rate mitigation for the residential class, provides rate options that allow NIPSCO's large industrial customers to help mitigate the impact of the increases they will experience as a result of this rate case and movement from special contracts, helps large industrial customers more efficiently operate their production, helps NIPSCO mitigate the need for additional capacity, allows NIPSCO to receive sufficient revenues to efficiently and economically provide service within its service area, and helps maintain the economic stability of NIPSCO's large industrial customers and the economic viability of the entire area. He said the Settlement is a comprehensive agreement and each term within the Settlement is essential to the overall reasonableness of the agreement and therefore he recommended the Commission approve the Settlement without any material changes.

(b) James R. Dauphinais. Mr. Dauphinais testified in support of NIPSCO Riders 675 and 676 under the Settlement. Mr. Dauphinais explained Rider 675 provides for interruptible electric service for large industrial customers and Rider 676 provides for back-up, maintenance and temporary electric service for large industrial customers. He emphasized the two riders are fundamental and critical components of the Settlement in light of the increases for large customers. Mr. Dauphinais noted the percentage base rate increase for large industrial customers of 20.317% on average for Rates 632, 633 and 634 compared to the general service class increase of 10.5864% on average for Rates 621, 623 and 624 and the residential customer class increase of 4.788% for Rate 611. He added that certain special contract industrial customers will be seeing increases well in excess of the 20.317% class average increase for Rates 632, 633 and 634. He stated Riders 675 and 676 are critical toward providing large industrial customers an opportunity to manage and partially mitigate these large base rate increases. Mr. Dauphinais testified the two riders are reasonably based on cost of service but also represent a keystone to the compromises that were arrived at by the Settling Parties in the Settlement. He urged the Commission to consider the Settlement as a complete package rather than isolating particular aspects of the Settlement from other aspects of the Settlement. He recommended the Commission find that Riders 675 and 676 in the Settlement are reasonable and approve the Settlement as filed in its entirety.

(1) Rider 675. Mr. Dauphinais provided an overview of Rider 675. He stated, historically, a number of NIPSCO's largest loads have received service on an interruptible basis, which allowed NIPSCO to avoid building or buying generation capacity to serve those loads. At the hearing, Mr. Dauphinais discussed both Rate 836 and Rate 845, which is a non-firm rate and under which customers pay the highest incremental fuel price. As such, it is basically a self-interrupting rate. He stated with NIPSCO's decision to avoid new special contracts for such loads and to migrate customers to firm tariff rates, addressing the rates, terms and conditions for interruptible service became a central issue that the Settlement comprehensively resolves in Rider 675. Mr. Dauphinais testified that Rider 675 offers a menu of curtailable (reliability) and interruptible (economic) service options that provide substantial value to NIPSCO and its firm service customers. He explained customers that commit to service pursuant to Rider 675 receive varying credits to the demand component of their bill in exchange for a lower quality of service relative to firm customers. He said Rider 675 provides an opportunity for Rate 632, 633 and 634 customers to lower their electric rates through demand charge credits by taking interruptible rather than firm service for all or some of their load, while at the same time providing lower costs to NIPSCO's other customers by lowering NIPSCO's costs for electric generation capacity and lowering NIPSCO's fuel and purchased power costs.

Mr. Dauphinais explained that total participation in Rider 675 is limited to 500 MW of interruptible capacity and that no more than $38.0 million in total demand charge credits will be paid to Rider 675 customers in any calendar year. He compared these limits to NIPSCO's Rider 581 as approved in the 43526 Order, which also was limited to 500 MW of participation, but authorized a higher level of credits to be recovered from firm customers of up to $40.5 million per year rather than the maximum of $38.0 million per year specified in Rider 675.

He also described the four different Rider 675 service options – Options A, B, C and D that provide various levels of demand charge credits based on the level of interruptibility for which an individual customer commits to provide. Mr. Dauphinais testified compensation under Rider 675 can be best thought of as being similar to that under Rider 581 except that, to the benefit of participating customers, they are not forced to try to fit into the "one size fits all" $6.75 per kW-month demand credit and interruptibility provisions of Rider 581, which also benefits NIPSCO and NIPSCO's firm customers.

Mr. Dauphinais described Option A, which requires a participating customer to be subject to reliability curtailments pursuant to the MISO requirements for Demand Resources with the exception that participating customers must be curtailable on four hours of notice rather than the less strict MISO requirement of 12 hours. The minimum contract term for Option A is only one year. He added that participating customers are not subject to economic interruptions under Option A and during reliability curtailments, participating customers curtail their demand down to their firm service level.

Mr. Dauphinais described the value provided to NIPSCO and its firm customers by customers participating in Option A. He explained that due to its short one year minimum commitment, Option A participation cannot be included in NIPSCO's long-term resource planning and, like short-term capacity purchases, cannot be relied upon by NIPSCO to be available year-to-year to maintain reliability and therefore does not provide the same capacity value as a new generation facility. However, he explained Option A participation does provide some benefit in allowing NIPSCO to reduce its near-term need for electric generation capacity and reducing NIPSCO's fuel and purchased power cost during system emergencies when reliability curtailments are called from Rider 675 Option A customers. He said the latter can be significant during a system emergency as it is possible under such conditions that MISO could be inducing scarcity pricing of up to $3,000 per MWh. Consequently, during the curtailment NIPSCO would be avoiding the purchase of any power at this price to serve the interruptible portion of the participating customers' load. He added that during emergencies, the curtailment of Rider 675 Option A customers will reduce the likelihood that NIPSCO's firm service customers will face involuntary curtailments of service.

Mr. Dauphinais testified that a demand charge credit of $1.00 per kW-month will be paid to Option A participants and, starting every subsequent February 1, NIPSCO will update the amount of the credit, subject to Commission approval, to reflect the current annual market price for capacity as determined by NIPSCO from market quotes from candidate bilateral market counterparties received in the preceding January. He explained that the compensation reflects most of the shorter term costs NIPSCO and its firm customers will avoid due to customer participation in Option A. He said the one year is long enough for NIPSCO to avoid the market price for the generation capacity requirement under MISO's resource adequacy requirements due to NIPSCO being able to claim Option A participating customer load as a MISO Demand Resource. He stated the $1.00 per kW-month amount represents NIPSCO's rough estimate of recent prices for short-term electric capacity, which NIPSCO will update every year. He noted that no additional compensation will be provided to Option A participating customers for the fuel and purchased power savings they will provide to NIPSCO and NIPSCO's firm customers when curtailments are called during system emergencies, but when considered in the context of the overall Settlement, the Industrial Group considers the agreed upon level of compensation under Option A to be reasonable for settlement purposes.

Mr. Dauphinais testified that the annual market price for capacity is currently lower than the cost for a new generation facility because of the current size of generation reserve margins in the MISO footprint. He noted, however, that new generation capacity cannot be built overnight and the current annual market price for capacity is a temporary situation. He said experience has shown that short-term market prices for capacity do not reflect the expected long-term cost for generation capacity and that, typically, short-term market prices for capacity significantly understate the long-term value of capacity when excess capacity exists and dramatically overstate the long-term value of capacity when capacity margins are tight. He added there is great uncertainty regarding the future of the large, relatively old coal-fired generation fleet located in the MISO footprint due to the Environmental Protection Agency's ("EPA") recently released Utility Maximum Achievable Control Technology ("MACT") rule for hazardous air pollutants and Cross-State Air Pollution Rule ("CSPAR") for nitrogen and sulfur emissions as well as expected future EPA regulations regarding cooling water. He said if the EPA keeps the tight deadlines it has proposed in its rulemakings, it could rapidly lead to a significant amount of coal-fired generation retirements. As an example, he pointed to a December 2010 study by The Brattle Group identifying 16 to 20 GW of coal-fired generation in the MISO footprint as being vulnerable to retirement by 2020. He said this could result in a rapid reduction in generation planning reserve margins within the MISO footprint and cause the market price of electric capacity to rapidly rise.

He also noted that, as long-term wholesale forward markets for electricity begin to mature, the market price for electric capacity should trend toward the avoided cost of new generation facilities. He cautioned, however, that even in a mature market, the current annual market price for capacity may be substantially lower or substantially higher than the avoided cost for a new generation facility depending on the circumstances present in the year in question.

Mr. Dauphinais also explained Option B. He said like Option A, Option B requires a participating customer to be subject to reliability curtailments pursuant to the MISO requirements for Demand Resources with the exception that participating customers must be curtailable on four hours of notice rather than the less strict requirement of 12 hours under the MISO tariff. Option B participants are also required to provide up to 100 hours per year of economic interruptions within certain restrictions and are required to have a minimum contract term of three years rather than the one year of Option A. He said Option B customers must reduce their load down to a firm service level when reliability curtailments or economic interruptions are called.

Mr. Dauphinais testified that Option B allows NIPSCO to reduce its cost for electric generation facilities and reduces NIPSCO's fuel and purchased power costs when reliability curtailments are called during system emergencies and, more significantly, during the up to 100 hours per year that NIPSCO can call economic interruptions of Option B customer load. He explained that because Option B requires a minimum contract term of three years, NIPSCO can recognize Option B participation in its resource planning decisions. He added the three-year commitment is sufficient to extend past the typical lead time of a simple cycle combustion turbine generation facility (approximately two years) and roughly reaches out to the typical lead time for a new, combined cycle generation facility (approximately three years). He said with Option B participation, NIPSCO can avoid the cost for new generation facilities that are needed to assure reliability and hedge the market cost of electric capacity and energy. He testified the avoidance of such generation facility costs is important because utilities like NIPSCO cannot rely year-to-year on capacity always being available in the short-term markets to maintain reliability.

Mr. Dauphinais stated that Option B provides for a demand charge credit of $6.00 per kW-month to participants. He stated the $6.00 per kW-month credit moves closer to the cost of a new simple cycle combustion turbine generation facility, but noted that it does not provide any additional compensation for the fuel and purchased power cost savings that NIPSCO will see and pass on to ratepayers through lower FAC adjustments as a result of economic interruptions by Option B participants. He added the credit is also $0.75 per kW-month lower than the demand charge credit that would have been paid in Rider 581, under the 43526 Order. He said, because the Settlement also includes Options C and D for Rider 675, which provide the opportunity for greater levels of compensation in exchange for shorter interruption notice, greater interruptibility, and/or longer minimum contract terms, the Industrial Group agrees that the proposed compensation level for Option B is reasonable for settlement purposes.

Mr. Dauphinais testified to the current estimated cost of a new simple cycle combustion turbine generation facility based on the United States Energy Information Administration ("EIA") review of its new generation cost assumptions in 2010. The results of that review identified that the total project cost for a new CCGT in the Indianapolis area would range from $676 per kW to $988 per kW installed in 2010 dollars, excluding finance cost, depending on the size and construction type. *See* Exhibit JRD-2 at 8-4 and 9-3. A review of the same combustion turbines in the Chicago area ranged from $772 to $1,107 per kW installed. Mr. Dauphinais said the estimated fixed O&M cost ran from $6.70 per kW-year to $6.98 per kW-year, which averages to $885.75 per kW installed (without financing cost) with a fixed O&M cost of $6.84 per kW-year. *Id.* at 8-6 and 9-4. He then converted these values into an estimated monthly levelized cost assuming a 50/50 debt to equity ratio and a 10.2% ROE, to yield a levelized amount of $10.79 per kW-month, including income taxes and property taxes.

Mr. Dauphinais added this value needs to be adjusted upward to reflect avoided planning reserve margin requirements and transmission losses. He explained planning reserve margin is an additional amount of generation capacity a LSE, such as NIPSCO, must carry above its forecasted annual system peak load, plus transmission losses, in order to meet resource adequacy requirements. He said typically, planning reserve margins require 12% to 18% more installed generation capacity than a LSE's forecasted annual peak system load, plus transmission losses. He added that in MISO, the situation is a little more complicated because the MISO's resource adequacy requirements are specified in terms of Unforced Capacity ("UCAP") rather than Installed Generation ("IGEN"). He explained UCAP is the rated installed capacity of a generation facility derated down to reflect the expected forced outage rate of that generation facility. UCAP reflects both the size and expected availability of the resource. He stated that in UCAP terms, the MISO's planning reserve margin is currently 3.81%, but when adjusted into IGEN terms by the average forced outage derate of installed capacity, it amounts to approximately 12.06%, citing to MISO Planning Year 2011 LOLE Study Report, December 2010 at page 3.

Mr. Dauphinais testified that for resource adequacy requirement purposes, LSEs within the MISO footprint are allowed to exclude from their forecasted system peak load plus transmission losses their interruptible load that qualifies as a Demand Resource, along with the transmission losses associated with that Demand Resource. He said as a result, LSEs do not need to carry capacity for the planning reserve margin and transmission losses for that interruptible load and, therefore, every MW of interruptible load is worth the same amount of generation capacity plus the planning reserve margin and transmission losses associated with that interruptible load. As an example, he said if in IGEN terms the planning reserve margin is 12% and the transmission loss factor is 3%, for resource adequacy purposes, 100 MW of interruptible load that qualifies as a MISO Demand Resource is worth the same as 115 MW of installed generation capacity. He testified that adjusting his current estimate of the cost of new CCGTs to reflect planning reserve margin and transmission loss savings results in $12.38 per kW-month using MISO's current IGEN planning reserve margin value of 12.06% and MISO's estimated summer average system transmission loss factor of 2.4%.

Mr. Dauphinais also explained why his current estimated capacity value is higher than his estimated value in Cause No. 43526. He said his testimony in this case reflects more recent estimates from EIA and second, the total demand charge credit he recommended in Cause No. 43526 for curtailments and interruptions that are equivalent to those proposed here for Option B was $8.05 per kW-month. He noted that estimate consisted of a $6.75 per kW-month credit for reliability curtailments and an additional $1.30 per kW-month credit for those customers who elected to participate in economic interruptions. He stated that, in his 2008 Rate Case testimony, he selected a low-end estimate of capacity value of $6.75 per kW-month to be conservative and conservatively used the amortization method NIPSCO uses in its annual avoided cost price filing, which does not fully capture NIPSCO's levelized cost of new generation and does not count the planning reserve margin benefits of curtailments. He said he was conservative in estimating the reliability curtailment credit in that proceeding because he was recommending an additional credit to reflect the value of the economic interruptions being provided. Because the 43526 Order did not approve the additional demand charge credit, he said it is no longer reasonable to use a conservatively low estimate of capacity value for curtailments. He stated a more appropriate approach would be to average the four capacity savings values presented on page 57 of his direct testimony in Cause No. 43526, use the same amortization method he used in Exhibit JRD-3 in this proceeding, adjust the average value up to reflect avoided planning reserve margin costs and then, finally, adjust up the value to reflect losses. He explained the average of those four values is $8.34 per kW-month for capacity only and when adjusted to use his Exhibit JRD-3 amortization method the value is $11.12 per kW-month. *See* Exhibit JRD-4. He added that, with a 12.06% planning reserve margin and 2.4% transmission losses, the adjusted value is $12.52 per kW-month. *Id.*

Mr. Dauphinais went on to explain that his $12.38 per kW-month avoided generation facility capacity cost estimate does not include the fuel and purchased power cost savings NIPSCO and its firm customers will receive from economic interruption of Option B Rider 675 customers. He estimated the additional savings that will be provided to NIPSCO and its firm customers from economic interruption of Rider 675 Option B customers under current fuel and purchased power costs. He examined the cost difference between the economic interruption buy-through rate and the normal Rate 632, 633 and 634 energy rates for the market conditions from July 27, 2010 through July 26, 2011 during periods when economic interruptions would occur.

From that data, he estimated a savings of approximately $0.69 per month for every kW of economic interruptions for Rider 675 Option B customers. *See* Exhibit JRD-5. He noted that estimate is under current fuel and purchased power costs and that the savings provided to NIPSCO and its firm customers from the economic interruption of Option B participants would be greater under higher fuel and purchased power costs.

Mr. Dauphinais explained that Option C, while similar to Option B, differs in three very important ways. He said first, Option C participants must be able to interrupt or curtail their load with a one-hour notice rather than the four-hour notice of Option B; second, Option C participants must commit to a contract term of no less than seven years rather than no less than the three years of Option B; and third, NIPSCO can call an unlimited number of reliability curtailments and those curtailments are not limited in duration. He explained that these features allow Option C curtailments and interruptions to closely approximate, or in some respects exceed, the performance of NIPSCO's existing CCGTs.

Mr. Dauphinais gave an example of how Option C interruptions and curtailments can exceed the performance of NIPSCO's existing CCGTs. He testified that in response to NLMK Data Request 1-3, NIPSCO identified the expected forced outage rates of its Bailly, Mitchell and Schahfer combustion turbines to be no lower than 27% in 2010 (NLMK Cross Exhibit 2). He said in contrast, Option C curtailments, which must be made available within an hour, must be 100% reliable and available when called. If an Option C customer fails to fully perform in response to a curtailment request even one time, Rider 675 requires the customer be disqualified from Rider 675 for three years.

Mr. Dauphinais testified Option C provides a more flexible tool for NIPSCO to deal with reliability issues on its system because if a reliability problem develops, NIPSCO must wait on Option A and B curtailments for four hours, while NIPSCO can call on Option C curtailments in one hour. He added that, unlike with Options A and B, NIPSCO is not limited in regard to the number of Option C reliability curtailments it may call per 12 rolling month period. He said both of these attributes further decrease the likelihood NIPSCO will have to call involuntary curtailments of firm customer load during a system emergency. He added that, if market prices unexpectedly rise above NIPSCO's FAC benchmark price for purchased power, NIPSCO does not have to wait four hours to receive the benefit of economic interruptions from Option C participants because it can start receiving economic interruptions from them in one hour rather than four hours. He said the net effect of these differences is to make Option C participation provide flexibility closer to that of a generator.

Mr. Dauphinais also explained that the minimum term of seven years provides greater reliability and economic value to NIPSCO and its firm customers. He said NIPSCO can consider Option C participation in its resource planning out to a longer planning horizon than it can for Option B participation, and the longer the period covered the greater the likelihood that arrangement will successfully protect against extreme volatility in the capacity market since the likelihood of such volatility increases as the length of time considered increases.

Mr. Dauphinais testified that the demand charge credit of $8.00 per kW-month provided under Option C appropriately moves closer to the full avoided cost of a simple cycle combustion turbine generation facility in light of the reliability, short notice to perform and longer term commitment features he described. He added that, as with Option B, Option C does not provide discrete compensation for economic interruptions, which he estimated for Option C to be an additional $0.94 per kW-month above avoided capacity value under current fuel and purchased power costs. *See* Exhibit JRD-5. He said as a result, the demand charge credit provided by Rider 675 for this level of service is conservative compared to the total benefits provided to NIPSCO and its firm customers.

Mr. Dauphinais testified that Option D incorporates and expands upon all the benefits provided to NIPSCO and its firm customers by Options A, B and C. He explained, Option D is the same as Option C except in regard to four major areas. First, the notice for curtailments and interruptions is only 10 minutes rather than one hour; second, up to 200 hours of economic interruptions can be called versus the 100 hours of Option C; third, a minimum contract term of ten years is required rather than the seven years of Option C; and finally, the curtailments and interruptions under Option D are reductions down by a certain number of MW rather than a reduction down to a firm service level. He testified that these differences provide an even more flexible tool for NIPSCO to deal with reliability issues on its system because with the 10-minute notice under Option D NIPSCO does not need to wait the four hours of Options A and B, or even the one hour of Option C, for curtailments. He said this further reduces the likelihood NIPSCO will have to call involuntary curtailments of firm customer load during a system emergency. He added, the 10-minute notice for economic interruptions builds on Option C and further reduces the delay associated with receiving the benefit of economic interruptions when needed. He said the 10-minute notice combined with the additional 100 hours of economic interruptions required of Option D participants should alone provide additional fuel and purchased power savings for NIPSCO and its firm customers of approximately $0.61 per kW-month of optional interruptible load under current fuel and purchased power costs. He added this value is in addition to the $0.94 per kW-month in fuel and purchased power savings that is estimated from the Option C level of interruptibility.

Mr. Dauphinais explained that because the interruption notice is 10 minutes and interruptions are down by a specified amount of MW rather than down to a specified firm service level, the flexibility provided to NIPSCO under Option D rises to the point where NIPSCO may be able to use, or at least begin to analyze the possibility of using, Option D participation as a MISO Demand Response Resource to provide operating reserves. He said this offers additional potential value to NIPSCO and its firm customers. He added that, the 10 year minimum term for Option D builds further on the greater reliability and economic value benefit provided to NIPSCO and its firm customers from the seven year minimum term of Option C participation.

Mr. Dauphinais testified the combination of additional flexibility, additional economic interruptions and a longer contract commitment makes the demand charge credit of $9.00 per kW-month appropriate. He added the $9.00 per kW-month amount is also significantly less than the approximately $13 per kW-month demand charge credit currently paid under Rate 836, the closest current equivalent to Rider 675 Option D service. He testified that while it could be argued the compensation being provided to Option D customers falls short of the value being provided to NIPSCO and its firm customers, the Industrial Group agrees the proposed compensation is reasonable in the context of the overall Settlement because the customer who would utilize this service would also be able to benefit from the new Rate 634, which works in conjunction with Option D of Rider 675.

(2) Rider 676. Mr. Dauphinais testified Rider 676 as proposed in the Settlement explicitly provides for backup and maintenance service for cogeneration systems serving large industrial customers in addition to general temporary service. He added the proposed terms, rates and conditions for general temporary service have been made much more reasonable than those originally proposed in this proceeding. Rider 676 is only available to Rate 632 and 633 customers.

Mr. Dauphinais stated the federal Public Utility Regulatory Policy Act of 1978 ("PURPA"), as amended by the Energy Policy Act of 2005, was intended to encourage conservation and efficient use of energy resources, including the encouragement of Cogeneration and Small Power Production Facilities. He said the encouragement of cogeneration in particular reduces the amount of capacity utilities such as NIPSCO require to serve their customers and is environmentally friendly due to the very high efficiency of cogeneration facilities such as the Portside Cogeneration Facility.

Mr. Dauphinais explained that PURPA generally requires electric utilities to sell electric energy to qualifying cogeneration facilities and qualifying small power production facilities (collectively, "QFs"). It also generally requires electric utilities to purchase electric energy from QFs. He said PURPA requires that FERC establish rules for just and reasonable rates for sales to QFs that also are in the public interest and do not discriminate against QFs. Similarly, it requires FERC to establish rules for the rates at which purchases are made from QFs such that they are just and reasonable to electric consumers of the electric utility, in the public interest, and do not discriminate against QFs. He noted the FERC's current rules for QFs are contained in of 18 CFR § 292.

Mr. Dauphinais testified the FERC rules, among other things, require the purchase of electric energy and capacity from QFs at a rate no greater than the cost the electric utility avoids by making the purchase. He said this ensures electric consumers do not subsidize QFs. As a result, electric consumers do not pay more for electricity than they would have if the utility had purchased the power elsewhere or generated the power in its own facilities.

He emphasized the FERC rules also require that the rates for Backup and Maintenance Power for QFs reflect the cost of service to provide such power. He said this includes reflecting the non-simultaneous nature of QF forced outages and the low likelihood of such outages during the electric utility's system peak, and includes the recognition of the coordination of QF scheduled maintenance outages with the scheduled outages of the electric utility's own facilities. He stated all of this helps to ensure that these rates are (i) just and reasonable and (ii) do not result in electric consumers subsidizing QFs. Mr. Dauphinais added the IURC's own Rule 4.1, Cogeneration and Alternative Energy Production Facilities, is meant to be consistent with, and expands upon, the FERC rules for QFs.

Mr. Dauphinais stated FERC defines Backup Power as:

> "Electric energy or capacity supplied by an electric utility to replace energy ordinarily generated by a facility's own generation equipment during an unscheduled outage of the facility." (18 CFR § 829.101(b)(9).)

and Maintenance Power as:

> "Electric energy or capacity supplied by an electric utility during scheduled outages of the qualifying facility." (*Id.* at (b)(11).)

Mr. Dauphinais testified that there are two reasons why Backup and Maintenance Service is being explicitly provided for in Rider 676 in the Settlement. He said first, outside of defaulting to the applicable firm rate schedule, NIPSCO did not provide a standard tariff for backup and maintenance service in its original rate filing in this proceeding. Second, it resolves a long-standing problem regarding the lack of a standard NIPSCO tariff that is specifically designed for Backup and Maintenance Service. He explained that, previously, such service had to be negotiated on a case-by-case basis or taken as temporary service which NIPSCO only offered on an as-available basis. He said the addition of specific Backup and Maintenance Service provisions reasonably resolves these issues when taken in the context of the overall Settlement.

Mr. Dauphinais provided an overview of the Maintenance Service provisions. He explained Maintenance Service must be requested at least 30 days in advance of need and it may not be requested for days in the months of June, July, August and September. He said it also may not be requested for more than 60 calendar days in any 12-month rolling period. A qualifying request for Maintenance Service cannot be denied by NIPSCO, but Maintenance Service is subject to reliability curtailments prior to other firm customers being curtailed when curtailment of Rider 675 interruptible customer load is insufficient to address a reliability issue. He stated the demand charge for Maintenance Service is $0.44 per kW-day in January, May and December and $0.25 per kW-day in February, March, April, October and November. The energy rate is the same as that for Rate 632 or 633, as applicable. He said customers needing Maintenance Service in June, July, August and/or September or for more than 60 days per rolling 12 months must take such service under the Temporary Service provisions of Rider 676.

Mr. Dauphinais testified that for settlement purposes the Maintenance Service provisions of Rider 676 are reasonable because the provisions provide for standard tariff service specifically designed for maintenance service and the provisions "... take into account the extent to which scheduled outages ... can be usefully coordinated with scheduled outages of the utility's facilities" as required under 18 CFR Ch. I, § 292.305(c). He noted Maintenance Service only can be taken during months of the year when NIPSCO will have spare capacity due to lower loads, and the proposed demand charges reflect the greater amount of spare electric capacity

NIPSCO will likely have in February, March, April, October and November. He added the proposed $0.44 per kW-day and $0.25 per kW-day demand charges are respectively equivalent to pro-rated monthly demand charges of $13.38 per kW-month and $7.60 per kW-month, which represent a reasonable contribution to NIPSCO's fixed costs for a service not driving NIPSCO's generation capacity needs.

Mr. Dauphinais also described the Backup Service provision of Rider 676 in the Settlement. He explained that Backup Service is only available to backup cogeneration systems serving large industrial customers that meet certain minimum efficiency standards. Customers must provide initial notice of a request for Backup Service within 60 minutes of the loss of generation and the customer is required to, on an ongoing basis, provide an update to NIPSCO on the generation outage. He said the Backup Service provisions may only be used for up to 45 calendar days per cogeneration system per 12 rolling months and, like with Maintenance Service, NIPSCO cannot deny a qualifying request for Backup Service, but service is subject to curtailment before other firm service when curtailment of Rider 675 interruptible load is insufficient to address a reliability issue. He stated the daily demand charge for Rider 676 Backup Service is a proration of the Rate 632 or 633 demand charge, as applicable, and the energy charge is equal to the real-time MISO LMP for the NIPSCO load zone, plus a non-fuel energy charge of $0.0035 per kWh.

Mr. Dauphinais testified for settlement purposes the Rider 676 Backup Service provisions are reasonable because the Backup Service provisions provide a significant contribution to NIPSCO's fixed cost and the payment of energy at LMPs plus an adder rather than NIPSCO's Rate 632 and 633 average fuel cost charges. He noted it could be argued the energy charges should be based on something closer to average fuel cost rather than potentially much higher LMPs, but when taken in context of the overall Settlement, including the Maintenance Service and revised Temporary Service provisions of Rider 676, the Industrial Group agrees the Backup Service provisions of Rider 676 are reasonable for settlement purposes.

Mr. Dauphinais also described the Temporary Service provisions of Rider 676 in the Settlement. He testified Temporary Service is available by request from NIPSCO but, unlike with Maintenance Service and Backup Service, NIPSCO can deny a request for Temporary Service if the day-ahead LMP for the NIPSCO load zone exceeds NIPSCO's purchased power benchmark price under its FAC. He added, a customer can elect buy-through Temporary Service if its Temporary Service request is denied, provided NIPSCO has not initiated a reliability curtailment on its system. He noted Temporary Service that is granted by NIPSCO is subject to reliability curtailments before the curtailment of other firm customers when curtailment of Rider 675 interruptible load is insufficient to address a reliability issue. He said there is no limit on the length of time Temporary Service is taken, but the demand charge for granted Temporary Service becomes progressively larger the longer the service is taken in any 12-month rolling period. As an example, he noted the demand charge for the first 30 days of service is $0.58 per kW-day (effectively $17.64 per kW-month prorated), while the demand charge after 90 days of service is $2.32 per kW-day (effectively a very large $70.57 per kW-month prorated). He added the demand charges do not apply to buy-through Temporary Service. He said accepted Temporary Service requests pay the Rate 632 or 633 energy rate, as applicable, while buy-through Temporary Service pays an energy rate equal to the real-time LMP for the NIPSCO load zone plus a non-fuel energy charge of $0.0035 per kWh.

Mr. Dauphinais stated that for settlement purposes the Temporary Service provisions of Rider 676 are reasonable because the proposed provisions reasonably provide a significant contribution to NIPSCO's fixed costs that strongly discourages usage as the length of service taken grows longer, while providing access to energy at average fuel cost when the day-ahead LMP is below NIPSCO's FAC purchased power benchmark price. He said that as such, the provisions are reasonable when taken in the context of the overall Settlement.

Mr. Dauphinais summarized his conclusions and recommendations, stating Rider 675 and 676 as proposed in the Settlement are reasonable in the context of the overall Settlement and are fundamental and critical components to the Settlement that provide large industrial customers, the rate class taking the largest percentage base rate increase under the Settlement, a reasonable opportunity to mitigate that increase. He recommended the Commission accept the Settlement as filed in its entirety.

9. <u>Testimony Opposing the Settlement</u>. Hammond presented the testimony of Reed W. Cearley opposing certain aspects of the Settlement. Mr. Cearley summarized his understanding of Rider 675 and stated that the Commission should not grant NIPSCO any "pre-approval" for the recovery of demand credits under Rider 675. He testified that the amount of interruptible service made available by NIPSCO should not exceed NIPSCO's actual need for capacity or "hedging," and that the value placed on interruptible service in Rider 675 is "overstated and excessive." He testified that the cost for interruptible credits associated with reducing capacity costs should be passed solely through the RA Tracker, and the cost for interruptible credits paid for economic interruptions should be passed solely through the FAC. He offered his opinion that the RA Tracker provides for a prudency review of "all charges related to NIPSCO's capacity purchases," including those costs associated with Rider 675.[7] Mr. Cearley compared NIPSCO's Hedging Plan, approved in Cause No. 43849, and the credits paid pursuant to NIPSCO's Rider 675 tariff offering. He stated that transactions entered into, consistent with the requirements of Rider 675, would be subject to prudency reviews in each RA Tracker and FAC periodic filing, rather than be approved in the rate case. Mr. Cearley noted that the Settling Parties agreed that a division of the Rider 675 credits was appropriate, with 75 percent being recovered in the RA Tracker and 25 percent being recovered in the FAC, but he suggested that credits for Option A should only be recovered in the RA Tracker, while costs associated with economic interruptions, should be passed through the FAC. Mr. Cearley quoted Mr. Dauphinais' testimony from Cause No. 43526, wherein he explained that interruptible service offerings may count as a Load Modifying Resource for purposes of MISO's capacity requirements, and therefore allow NIPSCO to avoid generation capacity or acquisition costs. Mr. Cearley cited NIPSCO's 2009 Integrated Resource Plan ("IRP"), of which the Commission took Administrative Notice. Mr. Cearley noted that in the 2015 to 2018 timeframe, NIPSCO expected to need two additional combustion turbine resources. With regards to economic interruptions, Mr. Cearley testified that because NIPSCO has a plan to hedge 50 percent of its projected MISO purchases, its spot market exposure is limited. He also stated that the rates being paid for the interruptible credits were too high. Mr. Cearley argued that a new CT would offer significantly greater hedging value than Rider 675.

[7] Intervenor Hammond Exhibit RWC, at 6.

Mr. Cearley noted that the allocation methodology proposed by the Settling Parties for Rider 675 is "unfair and discriminatory." Mr. Cearley suggested that the rate increase for all residential customers be limited to 4.5 percent. Finally, he stated that commercial and industrial customers should have the accrued interest on their deposits applied to their bills "one time per year."

10. Settling Parties Rebuttal Testimony. NIPSCO witness Shambo, OUCC witness Bolinger and Industrial Group witness Dauphinais all presented testimony responding to Mr. Cearley's testimony opposing the Settlement.

A. Frank A. Shambo. In his settlement rebuttal testimony, Mr. Shambo addressed three issues: (1) the appropriateness of Rider 675, (2) cost allocation within Rate 611, and (3) the unreasonableness of a requirement that NIPSCO refund accrued interest on customer deposits on an annual basis.

Mr. Shambo testified that Rider 675 is but one part of the Settlement and should not be considered in isolation from the balance of the agreement. He stated that Mr. Cearley is confusing NIPSCO's purchase of capacity in either the bilateral or MISO market with its offering of a tariff, which includes credits for customers agreeing to a curtailable and/or interruptible service. According to Mr. Shambo, while NIPSCO agrees that the prudence of any capacity purchases should be reviewed in the RA Tracker, the time to undertake a review of recovery of credits paid pursuant to a Commission-approved tariff is in the context of a general rate proceeding.

Mr. Shambo testified that Rider 675 does not give NIPSCO discretion to decide on a case-by-case basis whether to enter into an interruptible contract. If there is room under the $38 million cap, Rider 675 would require NIPSCO to enter into a contract requested by any eligible customer, subject to allocation procedures. He stated that because tracker proceedings are summary in nature, Mr. Cearley's proposal that recovery of the demand credits be dependent on after-the-fact prudence reviews in RA Tracker and FAC Tracker proceedings is not appropriate. Mr. Shambo stated that summary tracker proceedings are not vehicles to review and change tariffs. Further, he contrasted the Settlement's tracker mechanism with the alternative of including a level of credits in base rates as was ordered in Cause No. 43526. Under the 43526 Order methodology, a credit of $6.75 per kW-month for up to 500 megawatts of interruptible load is to be embedded in NIPSCO's basic rates. To the extent it is not fully used, the Commission instructed NIPSCO to credit any remaining amounts through the RA Tracker, and the Commission made an explicit finding that up to 500 megawatts at $6.75 / kw-month was an acceptable level of credits. Mr. Shambo noted that the product of those two variables equates to $40.5 million, an amount that is actually greater than the $38 million maximum amount of credits agreed to in the Settlement. He testified that under the 43526 Order methodology there would be no prudence review. He explained that the result should be no different when the same goal is more accurately accomplished through inclusion in tracking adjustments. Mr. Shambo noted that this is consistent with the treatment of other Indiana electric utilities. For example, the Commission has approved Vectren South's Reliability Cost and Revenue Adjustment that recovers interruptible billing credits without a prudence review.

Mr. Shambo testified that summary tracker proceedings have traditionally been in place to review cost items that change from period to period, which is not the case with the proposed credits within Rider 675. He noted that the Commission has repeatedly stated that FAC proceedings are statutorily required to be summary in nature. According to Mr. Shambo, deferring reasonableness reviews of interruptible rate option credits and participation levels to summary proceedings such as the FAC and RA Trackers would promote further litigation and disputes over these issues. Furthermore, he testified that the Settling Parties have resolved these important items and desire a positive working structure coming out of this rate case. According to Mr. Shambo, the reasonableness of the proposed Rider 675 terms, conditions and credits should be determined as part of the Commission's review of the comprehensive Settlement. He testified that substantial evidence has been presented in this proceeding for the Commission to decide on the prudence of the requested recovery of the demand credits under Rider 675, and that the Settlement is consistent with the 43526 Order. Because of this, Mr. Shambo testified that now is the time to determine the prudence of Rider 675 and the various credits associated with the interruptible options.

Mr. Shambo testified that the methodology proposed by the Settlement is in fact more transparent than the mechanism approved in the 43526 Order because NIPSCO must first provide the credits and then receive recovery. According to Mr. Shambo, the proposal in this proceeding is also more transparent, in that customers are paying for the credits in a separate tracker rather than as a component of basic rates and charges. He testified that it should be apparent that the purpose of the stated limits on Rider 675 service (both total megawatts and total dollars) is to establish a reasonable structure within which NIPSCO can administer the interruptible service program with qualified customers. Consequently, according to Mr. Shambo, an after-the-fact prudence review that Mr. Cearley seeks is unnecessary.

Mr. Shambo testified that post-hoc reviews would also create unnecessary and unreasonable risk for the utility and its customers and that long-term agreements create more certainty for all interested parties. He noted that, while it is true that NIPSCO has no signed contracts regarding future interruptible service, a level of service can be inferred from current customer behavior. Mr. Shambo pointed to two examples: (1) NLMK's agreement to take 90 MWs of interruptible credits in its Bridge Contract approved by the Commission in Cause No. 43866, and (2) NIPSCO's current Rate 836 customer that has a substantial quantity of interruptible load (110 MWs) operating under NIPSCO's currently effective tariff at a credit above what is being offered in this proceeding.

Mr. Shambo testified that the allocation of 75 percent being collected through the RA Tracker and 25 percent being recovered through the FAC Tracker is also reasonable, reflects a careful balancing of the interests of all parties, and is supported by the evidence in this proceeding. He also noted that the dollar cap is reasonable and actually less than the amount approved in the 43526 Order. According to Mr. Shambo, the emphasis on interruptibility and energy efficiency has grown since the 2008 Rate Case, and this explicitly includes the provision of tools for customers to enable them to operate more efficiently and to manage their own electric bills. Mr. Shambo noted that the Commission has subsequently entered orders requiring various Demand Side Management ("DSM") goals to be achieved and the FERC has entered an order requiring MISO to further promote demand response options.

Mr. Shambo explained that the flaw in Mr. Cearley's analysis is his basic premise that everything should be compared to short-term markets. He testified that resource planning performed by any regulated utility bearing an obligation to serve all load must necessarily take a longer term approach that must be capable of accommodating increasing uncertainties. Mr. Shambo stated that Mr. Cearley's argument assumes that NIPSCO should wait until there is a gap that cannot be met easily by the market and then instantly build a new facility with no load costs. He testified that there are substantial risks from failing to be proactive. For example, when the markets move to an environment in which supply is tight, the price will increase dramatically and also present NIPSCO with operational challenges to providing reasonably adequate service to its customers. Mr. Shambo testified that the evidence in support of the Settlement demonstrates that there are continuing risks to this market situation and that the caps were established to limit exposure to non-interruptible customers. He indicated that, while it is uncertain how much demand exists and at what price / service combinations, this was also true when the Commission approved 500 megawatts at $6.75 in the 43526 Order.

Mr. Shambo testified that Mr. Cearley generally ignores imminent events that will reduce capacity, including estimates by the NERC that utilities could retire between 33 to 70 gigawatts of existing generation capacity by 2015 as a result of new EPA rules including, among others, the draft Clean Air Interstate Transport Rule (replaced by the final CSPAR issued by EPA on July 6, 2011) and the Utility MACT standards. North American Electric Reliability Corporation, 2010 *Special Reliability Scenario Assessment: Resource Adequacy Impacts of Potential U.S. Environmental Regulation,* Oct. 2010 at 10. http://www.nerc.com/files/EPA_Scenario_Final.pdf ("NERC Report"). The NERC Report roughly estimates that the MISO footprint could see a 6%-9%+ reduction in adjusted potential capacity resources by 2018. *Id.* at 13. The NERC Report concludes that the estimated retirements of existing capacity across the nation could significantly decrease planning reserve margins and cause "considerable operating challenges." *Id.* at 41.

Mr. Shambo testified that, generally, future curtailments/interruptions cannot be predicted based upon past behavior and that the ability of NIPSCO to interrupt for economic reasons under Rider 675 is different than its ability to call for economic interruptions in the past. Mr. Shambo also noted that there were no buy-through provisions in the special contracts (other than the NLMK Bridge Contract), and, therefore, NIPSCO needed to be conscious of the fact that it was asking customers to drop load when it previously interrupted for economic reasons. Mr. Shambo testified that the Settling Parties have addressed these risks.

Regarding Mr. Cearley's comparison of the Settlement's proposed interruptible service to a hedging program, Mr. Shambo testified that the intent of NIPSCO's hedging program is to mitigate fuel cost volatility and not to shave the hourly price peaks. He noted that under the economic interruption program, if NIPSCO's customers buy through, they will not receive the benefit of pooled resources in the FAC. He stated that NIPSCO's current hedging program models the average on-peak MWhs that will be needed for each month and makes hedge purchases accordingly. Mr. Shambo noted that Rider 675's economic interruptions, however, are different and extremely valuable. He testified that, while Mr. Cearley apparently believes that NIPSCO will only economically interrupt if it is buying in the real-time market (i.e., load exceeds resources), NIPSCO in fact will only be doing so when it is advantageous to do so on behalf of its FAC customers. Mr. Shambo stated that, by giving NIPSCO the ability to essentially remove its interruptible customers from the FAC pool during those high priced hours, the Company will be able to consistently lower its fuel costs to the benefit of all other customers.

Mr. Shambo provided an example of market conditions experienced by NIPSCO in July of 2011 and the role existing interruptible customers played in mitigating the effects of those conditions. During the week of July 18, real-time hourly prices were at a substantially higher level than what had been seen previously. In particular, on July 21, real-time hourly prices reached as high as $454 per MWh with 8 of the 16 on-peak hours over $100 per MWh. According to Mr. Shambo, because NIPSCO was able to interrupt those customers who had an interruptible rate, NIPSCO was able to avoid purchasing power from MISO during these excessively high priced hours and thus lower the overall cost of power to the rest of its customers.

Regarding Mr. Cearley's testimony that the value placed on interruptible service for curtailments and for economic interruptions in Rider 675 is overstated and excessive, Mr. Shambo testified that some price needs to be established before a customer will sign for a service, and specifically, in regard to Option A, some price must be established for the first year to match a contract that a customer would sign. Furthermore, according to Mr. Shambo, NIPSCO must also know the price is recoverable before it is offered. He testified that the credit of $6.75 approved in the 43526 Order was for much more limited interruptions than Options C or D. It is more comparable to Option B, which is priced at $6.00.

In response to Mr. Cearley's argument that the proposed allocation of credits under Rider 675 is unfair and discriminatory, Mr. Shambo testified that customers are migrated to the services that most closely match their existing service. He went on to say that, to the extent NIPSCO is expanding the amount of interruptible service from that currently provided, existing customers should have first access, which is exactly what the Settlement provides. Mr. Shambo also said that limitations on available services frequently exist. For example, under NIPSCO's current 800 Series rates, only air separation facilities are eligible for interruptible service and even then it is limited to 110 megawatts (in combination with Rate 835), and the 43526 Order limited interruptible volumes to 500 megawatts.

The second area Mr. Shambo addressed was the cost allocation within Rate 611. He testified that although Mr. Cearley argues that the revenue requirement for Rate 611 would be better spread among Rate 611 customers so that the base rate increase is limited to 4.5%, it is a rate design issue driven by an increase in customer charge, rather than a cost allocation issue. Mr. Shambo testified that the Settlement includes an $11.00 customer charge, up from $5.95, which is a reasonable customer charge, comparable with other utilities in the state and the same charge to NIPSCO's residential gas customers.

Finally, Mr. Shambo expressed several concerns with Mr. Cearley's proposal that NIPSCO should be required to apply accrued interest on non-residential customer deposits to the customer's bill annually. First, he testified that the non-residential customer is required to timely pay its bill for 24 consecutive months to successfully request a return of its deposit, and to pay the accrued interest on an annual basis might be confusing to customers. Second, Mr. Shambo testified that he is aware of no utility in the State of Indiana that has such a requirement imposed upon them. Because of this, he stated that imposing such a requirement solely on NIPSCO, without any evidence as to why NIPSCO should be treated differently than the other utilities in the State, would be arbitrary and capricious. Finally, Mr. Shambo testified that customer deposits are included in NIPSCO's capital structure and serve to lower NIPSCO's required rate of return. Therefore, it is not correct for Mr. Cearley to say NIPSCO benefits by holding onto the accrued interest for as long as possible. He testified that to require NIPSCO to pay the accrued interest annually would increase the cost of the capital, without an attendant increase in NIPSCO's required rate of return. Mr. Shambo noted that, contrary to Mr. Cearley's testimony, the proposed rule does not provide for customers to request payment of the accrued interest on their deposits on a yearly basis. Mr. Shambo testified that the proposed rule provides that the interest accrues until the customer demonstrates its creditworthiness by having no delinquent bills, disconnections for nonpayment or bankruptcy filings over the last 24 months. The payment of interest is not dependent on an affirmative request by the customer, but it will automatically be paid when the deposit is returned or service is discontinued. Mr. Shambo agreed with Mr. Cearley that the rule provides for payment of simple (not compound) interest, but testified that is not unusual or inappropriate and is in line with the Commission's rules concerning residential customer deposits.

B. Tyler E. Bolinger. In his settlement rebuttal testimony, Mr. Bolinger addressed the issue of after-the-fact prudence reviews of Rider 675 contracts, as proposed by Mr. Cearley, who argued that recovery of NIPSCO's cost of providing interruptible credits should only occur after a prudence review of each Rider 675 contract transaction. Mr. Bolinger testified that it was not OUCC's intention or expectation that NIPSCO would be subject to a prudence review each time it enters into a contract under Rider 675. He explained that Rider 675 is a tariff offering that enables eligible industrial customers to elect to receive interruptible service in exchange for credits at levels established by Rider 675. Moreover, Rider 675 spells out the terms of eligibility, character of service, and the general terms and conditions of four different options (A through D). Mr. Bolinger testified that if Rider 675 is approved, then OUCC's review of Rider 675 contracts would focus on compliance with the terms of Rider 675. Public's Exhibit No. 1R, pp. 1-2.

Mr. Bolinger testified that, under Mr. Cearley's vision of Rider 675 prudence reviews, a party could challenge a Rider 675 contract as imprudent even if it strictly complied with the terms of Rider 675. Under this scenario, the Commission would be free to disallow costs as imprudent if, for example, it determined that NIPSCO entered into contracts in excess of some optimal or prudent amount even if NIPSCO was in full compliance with the terms of Rider 675, including the 500 MW cap.

Mr. Bolinger testified that OUCC would view contracts that comply with the tariff to be reasonable. OUCC's review of such contracts would focus on compliance with the Rider 675 tariff language. On-going review would focus on quantifying the cost of the credits and how they are recovered and on NIPSCO's management of the interruptible resources. Section B. 18. of the Settlement (p. 9) describes consulting resources available to OUCC to review (among other things) NIPSCO's use of interruptible resources.

Mr. Bolinger concluded that after-the-fact prudence reviews of each Rider 675 contract would inject tremendous uncertainty into the process for NIPSCO and eligible customers, which could undermine the Rider 675 program. Rider 675 is designed to transparently offer an approved tariffed service to eligible customers. If Rider 675 is approved, the Commission should make clear that NIPSCO and its eligible industrial customers can rely on NIPSCO's ability to offer its tariffed services without fear that the provision of tariffed service would later be deemed imprudent. *Id.*, p. 4.

C. James R. Dauphinais. In his settlement rebuttal testimony, Mr. Dauphinais first addressed the implications if Rider 675 under the Settlement was rejected or changed, including the underlying policy considerations for a usable interruptible service. He also addressed the approval procedure for Rider 675 credits, the need for and value placed on interruptible service for reliability curtailments and economic interruptions under Rider 675, and the proposed allocation of credits under Rider 675.

Mr. Dauphinais first noted it was ironic that, in many instances in his settlement testimony, Mr. Cearley referenced Mr. Dauphinais' direct testimony on NIPSCO's interruptible rate from Cause No. 43526. He said although Hammond was an intervenor in Cause No. 43526, at no time did Hammond raise any concerns with either the provisions of Rider 581 or NIPSCO's and the Industrial Group's testimony in that proceeding regarding those provisions. He added it cannot be denied the features for Rider 581 were inferior for firm customers versus comparable provisions in Rider 675. Mr. Dauphinais compared Rider 581 in Cause No. 43526 to Rider 675 under the Settlement. Rider 581 allowed:

- Up to 500 MW of participation with a total of $40.5 million in interruptible credits (versus the lower of 500 MW or $38.0 million in annual demand charge credits under Rider 675);

- A demand charge credit of $6.75 per kW-month for reliability curtailment and economic interruption requirements that are very similar to those under Option B of Rider 675 (versus the $6.00 per kW-month demand charge credit provided under Option B of Rider 675);

- A minimum term of three years (the same as for Option B of Rider 675); and

- Collection of $40.5 million annually in demand charge credits in advance by NIPSCO from customers entirely on a demand basis with unpaid credits refunded to customers through the tracker (versus no collection in advance for Rider 675 credits and recovery from customers of the cost of Rider 675 credits through a tracker on an energy and demand allocation basis).

Mr. Dauphinais testified that beyond these core features, the remainder of Rider 675 differs from Rider 581 primarily in that it reasonably provides greater flexibility in the form of Options A, C and D to allow eligible customers to choose the combination of curtailability, interruptibility and compensation that works best for them. He said the creation of this flexibility within the overall participation and cost limits of Rider 675 was a basic element of compromise among the Settling Parties in framing a comprehensive agreement.

Mr. Dauphinais stated that, conceptually, the addition of such flexibility for interruptible customers cannot be legitimately said to be unreasonable. He said if Rider 675 better meets the needs of interruptible customers, it will better optimize participation in Rider 675 to the benefit of NIPSCO and its firm electric customers. He stated the remaining issue then is whether: (i) the lower demand charge credit of Option A versus B is reasonably commensurate with avoidance of economic interruptions and shorter minimum contract term of Option A versus Option B, and (ii) the higher demand charge credits of Options C and D versus Option B are reasonably commensurate with the additional requirements placed on Option C and D customers versus Option B customers. He testified that both his direct testimony and his rebuttal demonstrate the change in demand charge credits under Options A, C and D versus Option B is in fact reasonably commensurate with the change in customer requirements under Options A, C and D versus Option B.

He added that another important consideration is that Rider 675 is an important part of the overall Settlement and parties comprising a wide variety of interests in this proceeding have worked hard together to produce the Settlement and have jointly asked the Commission to find that the Settlement, when considered in whole, is in the public interest. He noted that within the Industrial Group, there are a variety of interests, including firm customers who will be paying their share of the interruptible credits that Hammond is disputing. He also noted that his silence in regard to any issue raised by Hammond in this proceeding should not be interpreted as agreement with any position taken by Hammond regarding that issue.

He testified that clearly the interruptible service provisions of the Settlement are better for NIPSCO's ratepayers than the compliance rates NIPSCO filed in Cause No. 43526. He stated the total maximum level of interruptible credits recovered from ratepayers is reduced from $40.5 million under Rider 581 to $38 million under Rider 675; recovery of the interruptible credit is not included in base rates but is instead recovered 75% through the RA Tracker and 25% through the FAC; and the residential rate increase is significantly lower under the Settlement than it would have been under the compliance rates in Cause No. 43526, even when adding in the potential cost of full subscription of Rider 675. Rider 675 is more flexible and usable for potential interruptible customers than Rider 581.

Mr. Dauphinais added that Rider 675 is the result of NIPSCO's continuing discussions with its industrial customers, as the Commission directed NIPSCO to do in the 43526 Order. He said Rider 675 is one element of the Settlement through which the Settling Parties developed more narrowly tailored tariffs to meet the needs of both NIPSCO and its industrial customers and that he continues to recommend that the Commission approve the Settlement in its entirety as filed by the Settling Parties.

Mr. Dauphinais testified that while Hammond's testimony is crafted to avoid making specific recommendations, the combination of its prudency review and other arguments undermine the provision of any interruptible service. He said that he has focused his testimony on demonstrating that Hammond's suggestions have no merit because they are based on a flawed view of the capacity cost avoided through interruptible service and the value interruptible service provides to all customers, but that the broader policy implications of having interruptible service offerings should not be ignored.

He noted that scaling back interruptible service is not consistent with the Commission's broad policy objectives. He pointed to various proceedings in recent years on demand response initiatives, of which interruptible service is a part, and said the Commission has consistently supported expansion of such offerings.

(a) Recovery of Rider 675 Demand Charge Credit Costs Through the RA Tracker and FAC. Mr. Dauphinais responded to Mr. Cearley's argument that NIPSCO may not automatically recover any interruptible costs through its RA Tracker and FAC and that NIPSCO's granting of service to customers under Rider 675 should be subject to prudency review in those proceedings. Mr. Dauphinais explained that it was not the intention of the Settlement to require NIPSCO to demonstrate in its RA Tracker and FAC proceedings that it was prudent in its granting of service under Rider 675 to eligible customers for the obvious reason that the reasonableness of the provisions of Rider 675 should be determined at this time in this cause just as the Commission approved the provisions of Rider 581 in Cause No. 43526. He said the RA Tracker, which was approved in Cause No. 43526 for recovery of purchased capacity costs and to refund any unused interruptible credits, and the FAC were selected out of administrative convenience to avoid the need to establish a separate rate tracker for the recovery of the cost of interruptible credits. He explained Rider 675 does not grant NIPSCO the right to deny service to eligible customers until either the 500 MW or annual $38 million cap is reached and, as such, an adverse prudence determination can only be made against a utility when that utility has discretion. NIPSCO has no such discretion under Rider 675.

Mr. Dauphinais also testified that making interruptible service subject to prudency review was not consistent with how interruptible service has been provided in the past. He explained that NIPSCO has had tariffs offering interruptible service for over 25 years. In prior cases, the total amount of interruptible credits was reflected in base rates and not recovered through a rate tracker. Rather, the provision of interruptible service through base rates was considered in the base rate case and not subject to on-going prudency review. He said regardless of whether NIPSCO recovers credits through a tracker or instead includes the recovery of them in base rates, the service offered under the tariff is the same and the granting of that service to customers should not be subject to prudency review.

Mr. Dauphinais added that granting NIPSCO discretion to deny service to eligible customers under Rider 675 such that its decisions could be subject to prudence review in its RA tracker and FAC proceeding would be unprecedented, impractical and unduly discriminatory. He said the time to determine the reasonableness of a standard tariff rate of general applicability is when the rate is being approved by the Commission, as the Commission is doing in this proceeding for Rider 675 and the remainder of the Settlement tariff rates. Mr. Dauphinais stated Mr. Cearley had not identified any precedent in Indiana or any other regulatory jurisdiction where a utility must demonstrate the prudence of its decision to grant interruptible service to customers under a standard tariff rate of general applicability and that Mr. Dauphinais was not aware of any such requirement in any regulatory jurisdiction.

Mr. Dauphinais also explained why it is impractical to require prudence review of a utility's decision to grant interruptible service for an eligible customer under a standard tariff rate. He said first, utilities are not generally given any discretion to deny service to eligible customers under standard tariff rates of general applicability. Under such circumstances, a utility cannot possibly be found imprudent for granting such service. Second, such a prudency review requirement would effectively make the availability of interruptible service under a standard tariff rate very tentative, which would undermine any benefit provided by having a standard tariff for interruptible service. He said such a requirement would have a very chilling effect both in regard to economic development and economic retention in NIPSCO's service territory.

Mr. Dauphinais testified that most large industrial customers would expect an interruptible service offering in a service territory like NIPSCO's, which has one of the largest industrial bases of any utility in the country. He said potential manufacturers could skip over NIPSCO's service territory due to the lack of a true standard tariff rate of general applicability for interruptible service. He added the lack of such a true standard tariff rate also will reduce the attractiveness of continued operation by existing manufacturers in NIPSCO's service territory. He stated NIPSCO's large industrial customers, which are the ones most likely able to meet the interruptible requirements of Rider 675, not only compete globally, but also within their own corporate structure and that those customers evaluate shifting operations or production levels to other company locations with lower energy costs. He said the lack of an available standard interruptible rate could contribute to such a shift of operations or production levels. He testified that NIPSCO should seek to utilize the flexibility of the large industrial base in its service territory, rather than ignore the opportunities provided by it. He said Rider 675 better allows NIPSCO to utilize that flexibility.

Mr. Dauphinais explained that it is unduly discriminatory for a utility to be required to show the prudence of its decisions to grant service to eligible customers under a standard tariff rate for interruptible service because the effect is to have a utility treat captive retail customers that are potentially willing to accept interruptible service similar to sellers in the wholesale market. He stated that, as he has testified in the past before this Commission, industrial end-use customers are not generally in the business of selling interruptions and curtailments. He said industrial end-use customers are principally in the business to profitably produce their core product and when they curtail their energy consumption, these end-users can incur significant lost production costs and other costs they would not otherwise incur. He added these customers may also have to incur capital investments in order to take interruptible service. He said obviously it is not desirable to incur these costs, but if the reduced electricity cost for the customer resulting from agreeing to curtailment and interruption significantly exceeds lost production cost the customer will incur for the curtailment or interruption, the customer will generally be willing to curtail its consumption if it contributes to its goal of profitably producing its core product.

Mr. Dauphinais explained these end-use customers are not the same as merchants in the wholesale electricity market and as a result, the process of obtaining interruptible load cannot work the same way as for purchasing capacity and energy in the wholesale market. He said, instead, there needs to be standard tariff offerings of general applicability along with the option to negotiate customer-specific rates when unique circumstances justify such customer-specific rates. He added that the standard of avoiding undue discrimination requires the standard tariff rate of general applicability recognize differences in customer characteristics and needs. He said just as it would be unduly discriminatory to offer just a single standard tariff rate for all customers, so would it be unduly discriminatory to only offer a firm standard tariff rate to large industrial customers. He explained Rider 675 meets this need within reasonable limitations without making the availability of service tentative under the rate, whereas Hammond's proposal would undermine that availability and unduly discriminate against large customers who are interested in taking interruptible service.

Mr. Dauphinais also testified Hammond presented a very short-sighted view of the need for interruptible service and given the nature of the investments industrial customers need to make in order to sign up for interruptible service, they will tend to do so only in the context of a sustained interruptible service offering. He said Hammond's view that interruptible service might be offered at one level today and another tomorrow creates uncertainty for making these business decisions, and, therefore, increases the likelihood that industrial customers will not elect interruptible service. He said that this, in turn, would make continued operation in NIPSCO's service territory by these customers less viable and could lead to higher electric rates for all customers.

(b) Separation of Compensation for Reliability Curtailments and Economic Interruptions in Rider 675. Regarding Mr. Cearley's argument that the demand charge credit for reliability curtailments and economic interruptions should be separately stated and that participation in economic interruptions should be optional, Mr. Dauphinais testified the 75 percent demand, 25 percent energy allocation for the interruptible credits is part of the overall Settlement, and should not be criticized in isolation. He said when taken in the context of the overall Settlement, including the greater flexibility of the various options offered under Rider 675 versus Rider 581, the Industrial Group considers Rider 675 in the Settlement to be reasonable and it does not, at this time, need to be changed by separating out compensation for economic interruptions from reliability curtailments and making participation in economic interruptions optional. He added that the Settling Parties strived to make the core of Rider 675 (effectively Option B of Rider 675) very similar to Rider 581 in Cause No. 43526. He said in that proceeding, the Commission chose to make the economic interruptions under Rider 581 mandatory with no additional demand charge credit compensation for economic interruptions. He noted that while the Industrial Group does not necessarily agree with that approach, when taken in the context of the overall Settlement, the Industrial Group found it reasonable for settlement purposes to continue that approach in the Rider 675 provisions.

(c) Amount of Reliability Curtailments and Economic Interruptions Needed Under Rider 675.

(1) Reliability Curtailments. Mr. Dauphinais also responded to Mr. Cearley's argument that NIPSCO will need less than 225 MW of interruptible service for reliability purposes in the next few years. Mr. Dauphinais testified that there were a number of flaws with Mr. Cearley's observations, including the fact that NIPSCO's 2009 IRP was filed nearly two years ago on October 29, 2009 and may not reflect NIPSCO's current future needs for capacity. He added it was filed almost 10 months prior to the 43526 Order on August 25, 2010 approving up to 500 MW of interruptible service under Rider 581.

Mr. Dauphinais noted, even if NIPSCO's 2009 IRP remains a reasonable reflection of NIPSCO's future needs and resource plans, it called for the addition of 308 MW of simple cycle combustion turbine generation in 2015, the addition of 127 MW of simple cycle combustion turbine generation in 2020, 225 MW of interruptible load from 2011 through 2020 and approximately 130 MW to 140 MW of DSM from 2014 through 2020. He stated the 435 MW of combustion turbine generation additions could be avoided through additional interruptible load above 225 MW and added that, to the extent the 130 MW to 140 MW DSM goal is not realized, the shortfall could be addressed with yet additional interruptible load.

Mr. Dauphinais testified that NIPSCO is facing compliance with new emission and cooling water rules (e.g., CSPAR and Utility MACT rules) from the EPA that may ultimately dictate that NIPSCO consider early retirement of some of its existing generation capacity. Mr. Dauphinais concluded Mr. Cearley's claim that NIPSCO needs less than 225 MW of interruptible load for reliability purposes was not accurate and that there is substantial evidence of the need for at least 500 MW of interruptible load, as would be provided for under Rider 675.

Mr. Dauphinais also disputed Mr. Cearley's argument that he expects NIPSCO to contract for relatively little interruptible service in the next few years because there is an abundance of capacity in MISO and the current market price for capacity is low. Mr. Dauphinais referenced his direct settlement testimony that the current capacity situation in the MISO footprint is temporary and also noted new EPA rules will be going into effect in the near future that could lead to the early retirement of a large amount of generation in the MISO footprint.

Regarding Mr. Cearley's $0.01 per kW-month claim for the current market price of capacity, Mr. Dauphinais stated it is not an accurate estimate even for the short-term cost of capacity. He explained Mr. Cearley derived his $0.01 per kW-month value from the MISO Voluntary Capacity Auction ("VCA"), which is not a good indicator of the current short-term market price of capacity. Mr. Dauphinais stated the MISO VCA is a very thin and volatile auction for residual capacity and that very little of the total MISO footprint capacity need is traded within the VCA. He also knew of no electric utility that relies upon the VCA to meet its MISO resource adequacy requirements. As an example, Mr. Dauphinais stated that for July through September of 2011, less than 1.5% of MISO's peak footprint load cleared in the VCA.[8] Mr. Dauphinais added that over the period of June 2009 through September 2011, the VCA has had wild monthly swings from as low as $0.01 per MW-month to as high as $10,015.00 per MW-month. He said the VCA product also does not begin to resemble Option A of Rider 675 because Option A requires that a standard contract be executed in advance with a minimum contract term of one year, but the VCA product is residual capacity available for only one month that is cleared in an auction conducted only 40 days before the start of the month of delivery of that capacity. Mr. Dauphinais said this is why the Option A demand charge credit is not updated under Rider 675 using the MISO VCA results and instead will be updated based on the much more reliable surveys of the short-term bilateral capacity market where the vast majority of short-term capacity sales in the MISO footprint are transacted.

Mr. Dauphinais added that NIPSCO cannot heavily rely on short-term capacity purchases to meet its resource adequacy requirements because there is no guarantee such capacity will always be available in abundance in the short-term market. He said even NIPSCO's 2009 IRP recognized this through its very limited use of short-term capacity purchases. He stated that in

[8] Mr. Dauphinais testified the annual peak demand in the MISO footprint is approximately 100,000 MW (https://www.midwestiso.org/AboutUs/MediaCenter/PressReleases/Pages/NewPeakRecordSetinMISORegion.aspx) and Hammond's Exhibit RWC-5 at page 1 of 3 shows no more than 1,275 MW of capacity cleared in the MISO VCA for any month from June 2011 to September 2011.

contrast, Options B, C and D require progressively longer term commitments of three, seven and 10 years for interruptible service. He said, while the current short-term market price of capacity as determined from the bilateral market is a reasonable basis for updating the demand charge credit for Option A, it is neither an indication of the amount of Option B, C or D interruptible load that NIPSCO could use nor the proper price for demand charge credits under those options.

Addressing Mr. Cearley's observation that the low likelihood of future involuntary reliability curtailment of firm customers further diminishes the value of interruptible load for reliability curtailments, Mr. Dauphinais testified that the future likelihood of involuntary curtailment of firm customers is set at a minimum floor of one day in 10 years (i.e., a 10% likelihood of one day of interruption in any given year) in the loss of load expectation studies performed by MISO to determine the planning reserve margin requirements of load-serving entities like NIPSCO and, consequently, the future likelihood of involuntary curtailments of firm customer load is not a factor that NIPSCO uses to determine its resource adequacy needs. He said, instead, NIPSCO must acquire sufficient generation capacity and interruptible load to meet its planning reserve margin as dictated by MISO regardless of the likelihood of future involuntary curtailments of its firm customers. He noted though that, to the extent NIPSCO has insufficient capacity and interruptible load to meet its planning reserve margin requirement, the likelihood of involuntary curtailment of firm customers increases.

(2) Economic Interruptions. Mr. Dauphinais also addressed Mr. Cearley's fundamental misunderstanding of the purpose of NIPSCO's current hedging plan versus the economic hedging provided by simple cycle combustion turbines and economic interruptions under Options B, C and D of Rider 675. Mr. Dauphinais explained that NIPSCO's Commission-approved initial hedging plan in Cause No. 43849 is designed to manage in aggregate the price risk associated with NIPSCO's projected volume of spot natural gas purchases and spot electric energy purchases for the forthcoming two years and is not focused on purchases of electric energy above NIPSCO's FAC purchased power benchmark price. He noted that the risk or projected frequency of spot electric energy purchases being over the FAC purchased power benchmark is not even an input to the Cause No. 43849 hedging plan.

Mr. Dauphinais testified that NIPSCO's simple cycle combustion turbines and its Rider 675 B, C and D economic interruptions act as a long-term heat rate cap for NIPSCO's fuel and purchased power costs, which is a completely different role than the role played by NIPSCO's initial hedging plan in Cause No. 43849. He said as a result, the Cause No. 43849 hedging plan has no effect on the amount of simple cycle combustion turbine generation and Rider 675 Option B, C and D interruptions that is useful to NIPSCO. He added at most, NIPSCO's simple cycle combustion turbine generation and Rider 675 Option B, C and D economic interruptions influence the Cause No. 43849 hedging plan by shifting how the total volume of hedging is split between natural gas financial instruments and electric energy financial instruments. He said it has no influence on the total volume of hedging under the Cause No. 43849 initial hedge plan.

Mr. Dauphinais testified that NIPSCO needs to operate its system at the lowest reasonable fuel cost and therefore needs to obtain as many MWh of economic interruptions as possible at a cost less than the value provided by those economic interruptions. He pointed to his settlement testimony, which shows all of the demand charge credits that would be paid under Options B, C and D are less than the combined estimated reliability and economic dollar value that would be received by NIPSCO and firm customers. He said thus all of the economic interruptions provided for under Rider 675 are needed by NIPSCO.

(d) Value of Reliability Curtailments and Economic Interruptions Under Rider 675.

(1) Reliability Curtailments. Mr. Dauphinais responded to Mr. Cearley's argument that the initial demand charge credit for Option A should be determined in the first year in the same manner as in subsequent years by noting this is a provision of the overall Settlement that must be taken in context with the rest of the rate structures. He said in the context of the overall Settlement, the Industrial Group is willing to risk the actual short-term market price for capacity being greater than $1 per kW-month for the initial year and the $1 per kW-month demand charge credit is a reasonable initial price for demand charge credits for Option A.

In response to Mr. Cearley's testimony that NIPSCO does not need any Option B load for the next three years and his reliance on the July 2010 long-term market price for capacity, Mr. Dauphinais stated that in addition to the contribution interruptible service could make towards off-setting the additional combustion turbine generation capacity of 435 MW, the July 2010 price estimate Mr. Cearley cited is out of date because it was received prior to the market being aware of the pending pressure on existing capacity resources that will be imposed by the EPA's new emission and cooling water rules. Mr. Dauphinais added that even if Mr. Cearley's estimate was up to date and accurate, the price would not necessarily include the heat rate cap benefit provided by simple cycle combustion turbines and economic interruptions because capacity is usually traded in ISO and RTO markets without any right to call on energy from the traded capacity. Mr. Dauphinais also noted for a very similar level of curtailability, interruptibility and minimum term of service, Option B of Rider 675 pays a lower credit of $6.00 per kW-month versus the $6.75 per kW-month paid by Rider 581 in Cause No. 43526.

Mr. Dauphinais also disputed Mr. Cearley's statements that Options C and D should be rejected because they impose greater costs upon firm customers based on meeting additional curtailment and interruptibility requirements that are unnecessary. Mr. Dauphinais pointed to both NIPSCO witness Frank A. Shambo's and the Industrial Group's extensive evidence regarding the additional value provided to NIPSCO and firm customers by the additional requirements of Option C and D and that the level of compensation provided under these two options is less than the expected cost of a new simple cycle combustion turbine and is reasonably commensurate with the additional value being provided to NIPSCO and its firm customers by those two options.

Addressing Mr. Cearley's argument that the contract expiration term in Rider 675 means Options C and D really do not involve longer contract terms of 7 and 10 years, Mr. Dauphinais explained the purpose of the contract expiration clause. Mr. Dauphinais said if the terms, conditions and rates for curtailments, interruptions and compensation could not be changed by a base rate change during the term of the Option C and D contracts, then the Industrial Group would have no need for such an expiration clause. However, because Rider 675 is not a customer-specific electric service rate, it is subject to change by the Commission in base rate proceedings. Such a base rate change could change the terms, conditions and rates for Rider 675 service such that it is no longer reasonably viable for a particular customer to continue to take service under Option C or D and, thus, there is a strong need for the expiration clause. Mr. Dauphinais added it is not meant to be a means to circumvent the 7- to 10-year minimum term requirements of Options C and D and noted that one of the customers that will likely take service under Option D has been a Rate 836 interruptible service customer of NIPSCO for over 20 years. Mr. Dauphinais also noted that any assumption concerning when new base rates would be filed by NIPSCO, approved by the Commission, and become effective after this current cause is speculative and any customer committing to the terms specified in Options C and D must be prepared to perform as required for the entire stated term of years.

Mr. Dauphinais also addressed Mr. Cearley's testimony that no evidence has been presented that a shorter notice period than four hours is necessary to prevent involuntary curtailments of firm customers. Mr. Dauphinais stated if a system emergency occurs, the additional flexibility will reduce the likelihood that NIPSCO will have to involuntarily curtail firm customers because the notice period is shorter than the four hours required under Options A and B. He added that to the extent this is considered to be of limited value, it is really an argument that the proposed demand charge credit for Option B is too low relative to Options C and D. He also noted that his settlement testimony demonstrated NIPSCO's existing simple cycle combustion turbines (Mitchell 9, Bailly 10, Schahfer 16A and Schahfer 16B) had forced outage rates of no lower than 27% in 2010 and that NIPSCO's response to NLMK Data Request 1-3 shows that these turbines generally operate less than 100 hours per year and require roughly an hour to start (NLMK Cross Exhibit 2). He said in contrast, Option C and D curtailments must be available within an hour (10-minutes for Option D), must be 100% reliable and available when called and again noted that if an Option C or D customer fails to fully perform in response to a curtailment request even one time, the customer shall be disqualified from Rider 675 for three years.

Mr. Dauphinais disputed Mr. Cearley's testimony that the proposed demand charge credits for Options C and D are based on inflated values for a new combustion turbine. Mr. Dauphinais testified the proposed demand charge credits for Options C and D are in fact less than the estimated levelized cost of a new simple cycle combustion turbine generator. He noted again the $6.75 per kW-month value he used in Cause No. 43526 was conservatively low even two years ago and should not be used in this proceeding and pointed to the detailed testimony he provided in his settlement testimony and supporting data for his current estimate of $12.38 per kW-month, which is based on more recent EIA cost estimates. This estimate also reflects the planning reserve benefits of interruptible load that were not reflected in the $6.75 per kW-month estimate filed in Cause No. 43526. Mr. Dauphinais noted that Mr. Cearley's testimony does not directly dispute the: (i) use of up-to-date cost estimates, (ii) levelized cost estimate methodology, or (iii) incorporation of the planning reserve margin benefit provided by interruptible load.

Mr. Dauphinais also noted that while Mr. Cearley points to NIPSCO witness Gaske's direct testimony in this Cause regarding the estimated cost of the avoided cost of a combustion turbine, he neither defends Mr. Gaske's assumptions nor challenges the underpinnings of the calculations that Mr. Dauphinais provided. Mr. Dauphinais stated Mr. Gaske's direct testimony value of $6.58 to $7.00 per kW-month understates the combustion turbine cost avoided by interruptible load. Mr. Dauphinais explained that the overnight installed cost estimates of $610 to $617 per kW that Mr. Gaske used in developing his direct testimony are out of date. Mr. Dauphinais added even if he put more expensive Conventional Combustion Turbine generation aside, the EIA shows the estimated installed cost of an Advanced Combustion Turbine generation to be $676 per kW in the Indianapolis area and $772 per kW in the Chicago area in October 1, 2010 dollars. He said appropriately averaging these two estimates, the estimated cost in NIPSCO's service territory is approximately $724 per kW installed for an Advanced Combustion Turbine generator -- an amount significantly above Mr. Gaske's assumed $610 to $617 per kW values. He added that Mr. Gaske used the amortization method NIPSCO uses in its annual avoided cost price filing, but that method does not fully capture NIPSCO's levelized cost of new generation and does not count the planning reserve margin benefits of curtailments. He said that for the same reasons he identified in his settlement testimony discussing his own Cause No. 43526 cost estimate, Mr. Gaske's estimate is too conservatively low.

As to Mr. Cearley's statement that NIPSCO would pay for new capacity at the lowest cost reasonable option, not the average cost of its options, Mr. Dauphinais testified NIPSCO does not always have all the options available to it. As an example, he said a utility may only have a limited number of brownfield sites available to it and may need to build new generation at a greenfield site rather than a brownfield site. Similarly, a utility may not always be able to use an Advanced Combustion Turbine versus a Conventional Combustion Turbine due to size or other concerns. He stated when new generation is required, it does not necessarily align with the scale economics of standard generating unit sizes and, therefore, it is appropriate to average such cost estimate numbers.

Mr. Dauphinais testified that while he believes the estimate for the avoided cost should be based on an average of costs, if he just used the Advanced Combustion Turbine values from the EIA cost estimates, his $12.38 per kW-month estimate would fall to $10.23 per kW-month. He noted that, even without adding the economic interruption value provided by Option D above the capacity value of a simple cycle combustion turbine, this is substantially above the $8.00 per kW-month and $9.00 per kW-month demand charge credits proposed for Options C and D, respectively.

Mr. Dauphinais strongly disagreed with Mr. Cearley's testimony that interruptible service provided under Options C and D do not provide the benefit to ratepayers as the actual construction of a new combustion turbine. Mr. Dauphinais explained Mr. Cearley based his argument on the faulty premise that a new combustion turbine will be useful for 30 years, but Option C and D last only 7 to 10 years. He said Option C and D customers are only being paid compensation as they provide benefits to NIPSCO and its firm customers, which is very different than a new generator that requires an up front investment for the entire 30-year capital cost of the facility. He said history has shown that customers do not necessarily leave these types of interruptible service options when their contract term is up and noted the existing Rate 836 customer has continuously taken interruptible service for over 20 years with several extensions to its power supply agreement with NIPSCO. He said the reason customers will remain under these rates is that short-term spikes in the short-term market price for capacity cannot be relied upon to confidently predict the electricity cost savings that can be achieved from being interruptible. He stated that, to the extent possible, these customers typically want to build reasonably fixed cost savings estimates into their business forecasts and Options B, C and D reasonably allow for this predictability. He added to be able to be interruptible under Rider 675, customers will need to invest in and maintain infrastructure, incur costs and manage production in ways they would not ordinarily do and customers are likely to want to maximize these investments over an extended time period. He said Options B, C and D are service options that customers will likely remain on even after the expiration of their initial term.

Mr. Dauphinais stated that Mr. Cearley's argument, that a new combustion turbine provides hedging value far in excess to Options C and D, was flawed. Mr. Dauphinais said first, a new simple cycle combustion turbine will not be dispatched for 8,190 hours per year but will only be dispatched when the energy offer submitted for it to MISO is accepted. He testified, in general, the offer will be accepted by MISO when the LMP at the generator's node is equal to or greater than the offer price and if the offer is cost-based, which is to be expected of a vertically integrated utility such as NIPSCO, the offer will be based on the combustion turbine's expected heat rate, a forecast price for same day natural gas that includes an upward adjustment to address price uncertainty and the combustion turbine's estimated variable O&M costs. He said using an assumed heat rate of 10,300 BTU per kWh,[9] an upward natural gas price uncertainty adjustment of 10%, a variable O&M cost of $12.29 per MWh[10] and generator node LMP that is 2.34%[11] lower than that at NIPSCO's load zone, a typical simple cycle combustion turbine would likely not have been dispatched more than 546 hours during the 12-month period ending July 26, 2011. He noted, however, this assumes the effective forced outage rate of such a turbine is 0%, which it is not. He said assuming an effective forced outage rate of approximately 6.5%, the turbine would typically not be available for 6.5% of the hours in which it would otherwise be dispatched.[12] He concluded the actual likely number of hours that the turbine would have been dispatched in the 12-month period ending July 26, 2011 is 511 hours[13] – a number substantially less than Mr. Cearley's 8,190 hours.

Mr. Dauphinais added the hourly per unit estimated energy cost savings provided by a combustion turbine is not the same as that provided by Rider 675 Option B, C and D economic interruptions. He stated the hourly per unit energy savings provided by a combustion turbine is equal to the LMP at the generator's node less the generator's fuel and variable O&M cost, while the hourly per unit savings provided by Option B, C and D economic interruptions is the LMP at NIPSCO's load zone plus the applicable non-fuel energy adder specified in Rider 675 less the firm energy rate the customer would have paid if it had not been interrupted. He calculated that at an assumed heat rate of 10,300 Btu per kWh, an assumed variable O&M rate of $12.29 per MWh and a generator node LMP that is 2.34% lower than that at NIPSCO's load zone, a typical new simple cycle combustion turbine would provide an estimated $34.93 per MWh of net energy savings for 511 hours for the 12-month period ending July 26, 2011, or a total annual projected energy savings of $17,849 (Exhibit JRD-7) and on a per kW of capacity basis, this is $1.49 per

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9 The average of EIA November 2010 estimates of 10,850 for a Conventional Combustion Turbine and 9,750 for an Advanced Combustion Turbine (Exhibit JRD-2 at pages 8-2 and 9-2).

10 The average of EIA November 2010 estimates of $14.70 for a Conventional Combustion Turbine and $9.87 for an Advanced Combustion Turbine (Exhibit JRD-2 at pages 8-6 and 9-4).

11 2.34% = 100% x [1- (100% / 102.4%)], where 2.4% is the assumed transmission loss factor.

12 He said NIPSCO cannot control when its generation experiences forced outages. Thus, there is an equal chance for them to occur when the generation would be dispatched as there is when it would not be dispatched.

13 511 = 546 x (100% - 6.5%).

kW-month.[14] He said this value compares to his settlement testimony estimated per unit savings of $82.80 per MWh for 100 hours for Option B ($8,280 annually or $0.69 per kW-month), $112.80 per MWh for 100 hours for Option C ($11,280 annually or $0.94 per kW-month) and $93.00 per MWh for 200 hours for Option D ($18,600 annually or $1.55 per kW-month) (Exhibit JRD-5).

Mr. Dauphinais stated that based on these estimates, Option B provides only $0.80 per kW-month less energy value than that of a new simple cycle combustion turbine, and Option C only provides $0.55 per kW-month less energy value than a new simple cycle combustion turbine while Option D is estimated to actually provide $0.06 per kW-month more energy value than a new simple cycle combustion turbine. He concluded Mr. Cearley's argument that a new combustion turbine would provide hedging value far in excess of economic interruptions under Options C and D has no merit.

Mr. Dauphinais demonstrated that if he combined these energy savings estimates versus that of a new simple cycle combustion turbine with his estimated avoided capacity cost of $12.38 per kW-Month for such a turbine, for Option B the net capacity and energy avoided cost would be $11.58 per kW-month; for Option C, it would be $11.83 per kW-month and for Option D, it would be $12.44 per kW-month. He noted these net values are all well in excess of the $6.00 per kW-month, $8.00 per kW-month and $9.00 per kW-month credits respectively provided under Options B, C and D.

Mr. Dauphinais also redid his estimates just using the November 2010 9,750 BTU per kwh heat rate and $9.87 per MWh variable O&M cost estimates for an Advanced Combustion Turbine rather than those for the average of that turbine and of a Conventional Combustion Turbine. He testified that for illustration purposes just using the EIA Advanced Combustion Turbine heat rate and variable O&M estimates, the turbine would be in merit for dispatch for an estimated 693 hours, which would fall to 648 hours due to an assumed forced outage rate of 6.5%. He said the average hourly per unit savings would be $32.81 per MWh that would total to $21,261 annually for 648 hours and amount to a per kW energy value of $1.77 per kW-month. He stated Option B would provide $1.08 per kW-month less energy value, Option C would provide $0.83 per kW-month less value, and Option D would provide $0.22 per kW-month less value. He added that even under such a very conservative assumption, Mr. Cearley's statement that a new combustion turbine would provide hedging value far in excess of economic interruptions under Options C and D would have no merit.

He added that when these particular energy savings estimates versus that of a simple cycle combustion turbine are combined with his $10.23 per kW-month estimate of the avoided capacity value of a combustion turbine based on EIA Advanced Combustion Turbine estimates, the net capacity and energy avoided cost would be $9.15 per kW-month for Option B, $9.40 per kW-month for Option C and $10.01 per kW-month for Option D. He noted that once again, these net values are still all well in excess of the $6.00 per kW-month, $8.00 per kW-month and $9.00 per kW-month credits respectively provided under Options B, C and D.

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[14] $1.49 = $17,849 / 12,000.

In response to Mr. Cearley's argument that NIPSCO should be required to receive a certificate of public convenience and necessity ("CPCN") granting service to eligible customers under Rider 675 Options C and D. Mr. Dauphinais testified Mr. Cearley has not identified any precedent in Indiana or any other regulatory jurisdiction where a CPCN is required prior to a utility granting service to eligible customers under a standard interruptible tariff rate of general applicability. Mr. Dauphinais added that, as with the prudence issue, he is not aware of any regulatory jurisdiction where a utility was required to have a CPCN to grant service to an eligible customer under a standard interruptible tariff rate. He also noted that, as with the prudency issue, under Rider 675 NIPSCO does not have the discretion to deny service to any eligible customer until the lower of the 500 MW or $38 million annual demand charge credit cap is met.

Mr. Dauphinais added that, as with the prudency issue, Mr. Cearley's proposed CPCN requirement would effectively make Option C and D service only available on a very tentative case-by-case basis, which undermines the purpose of having a standard tariff rate of general applicability, is unduly discriminatory and could adversely affect economic development and economic retention in NIPSCO's service territory. He said the time for the Commission to determine the reasonableness of a standard tariff rate of general applicability is when it is filed, not in a future proceeding, and that substantial testimony has been presented in this proceeding demonstrating that Rider 675 is reasonable as proposed under the Settlement.

(2) Economic Interruptions. Mr. Dauphinais disputed Mr. Cearley's testimony that the estimated value of economic interruptions is fundamentally flawed. Mr. Dauphinais testified that Mr. Cearley misinterpreted Mr. Dauphinais' estimates on the NIPSCO load zone LMP for the 100 to 200 highest cost hours in conjunction with the LMP price during all above-benchmark hours, as summarized on page 1 of 52 of his Exhibit JRD-5. Mr. Dauphinais explained that for Option B, he did not utilize the per unit value for the 200 most expensive LMP hours of the analysis period, but rather used a blend of the per unit value for all hours over the FAC benchmark during the period and the per unit value for the 100 highest cost LMP hours of the period that was weighted by a factor of two toward the all hours per unit value (Exhibit JRD-5, page 1 of 52, line 4). He explained he did so to appropriately account for the fact that with a four-hour notice and the other limitations of Option B interruptibility, NIPSCO will not be able to perfectly time the Option B economic interruptions to the 100 highest LMP hours of the year.

He added that none of his economic interruption value estimates assumed NIPSCO could perfectly time interruptions to the highest LMP hours of the year but he did recognize that as the notice time grows smaller, NIPSCO's ability to time the interruptions to the highest LMP hours would improve. For Option B, he assumed a 2:1 weight for the per unit value for all hours versus the per unit value for the 100 highest LMP hours and for Option C, which has a one-hour rather than four-hour notice requirement, he assumed a 1:2 weighting on the per unit value for all hours versus the per unit value for the 100 highest LMP hours.

For Option D, which has 200 hours of interpretability versus 100 hours and a notice of 10 minutes rather than one or four hours, he used a 1:4 weighting on the per unit value for all hours versus the per unit value for the 200 highest LMP hours. In his judgment, he has reasonably accounted for the greater likelihood of successful optimization by NIPSCO of the shorter interruption notice of Options C and D while reasonably reflecting NIPSCO will not be able to perfectly time the calling of these economic interruptions.

Mr. Dauphinais addressed Mr. Cearley's claims that actual NIPSCO economic interruptions called during the 12-month period shows NIPSCO will not be able to time the calling of interruptions well. Mr. Dauphinais first noted Rider 675 was not in effect during the 12 months ending July 26, 2011 and the terms and conditions of the interruptible service NIPSCO was providing during that period were likely different than those of Rider 675. He added that under Rate 836, NIPSCO has not necessarily called interruptions when the LMP is over its FAC purchased power benchmark price. Therefore, the call of economic interruptions under NIPSCO's current interruptible service provisions is not an indicator of NIPSCO's future call of economic interruptions under Rider 675. He added the Industrial Group is under no illusion that NIPSCO will not call all of the economic interruptions NIPSCO is entitled to under Rider 675, and the Industrial Group fully expects NIPSCO to completely use the economic interruption hours of Rider 675 and to the greatest extent reasonably possible optimize the call of those economic interruptions in the highest LMP hours of the year.

Mr. Dauphinais also explained why he disagreed with Mr. Cearley's testimony that he incorrectly assumed NIPSCO will interrupt customers to the extent allowed. He said Mr. Cearley bases his argument on the amount of economic interruptions called by NIPSCO under its existing interruptible service provisions during 2011 and as he just discussed, the amount of interruptions under NIPSCO's current interruptible service provisions is not an indicator of the interruptions NIPSCO will call under Rider 675.

Mr. Dauphinais testified that it appears Mr. Cearley also misunderstands how the economic interruption provisions of Rider 675 work and interact with NIPSCO's MISO energy market settlements. Mr. Dauphinais said Mr. Cearley continues to try to incorrectly tie economic interruptions to NIPSCO's Cause No. 43849 initial hedge plan but that the Cause No. 43849 hedging plan performs a different role than NIPSCO's simple cycle combustion turbine generation and economic interruptions under Rider 675 Options B, C and D. He again noted, there is very limited, if any, interaction between the two.

Mr. Dauphinais also testified Rider 675 very clearly allows NIPSCO to call economic interruptions (within the limitations of Options B, C and D) whenever the real-time LMPs for the NIPSCO load zone are reasonably forecast to be in excess of the FAC purchased power benchmark. He said there is no requirement that NIPSCO be a net purchaser of power from MISO in that hour. He added if the customer chooses not to buy-through, the effect in NIPSCO's energy market settlements with MISO will be to avoid clearing that customer's load in the MISO real-time market, which will cause NIPSCO to earn a credit from MISO for the interrupted customer's load equal to the real-time LMP. He said NIPSCO will earn this credit from MISO in real-time settlements whether or not NIPSCO is a net purchaser from MISO during the hour of interruption. Mr. Dauphinais also explained if the Rider 675 customer chooses to buy-through the interruption, the customer pays the same real-time LMP credit to NIPSCO that NIPSCO would have earned in the real-time market from MISO if the customer had actually interrupted its load. Mr. Dauphinais said his economic analysis in Exhibit JRD-5 correctly reflects all of these interactions and is not flawed.

(e) Rider 675 Eligibility Discrimination Issue. Mr. Dauphinais also disagreed with Hammond's claim that Rider 675 is discriminatory. He testified Rider 675 will be a tariff offering available to all customers meeting the eligibility criteria in the tariff and the prioritization Hammond complains about comes into play if, and only if, there is more interest in the tariff than the tariff allows (500 MW or $38 million annually in credits). He said in that scenario, it is reasonable for existing interruptible customers to receive the initial allocation of interruptible capacity since those customers have been providing interruptions for some time and have made significant investments over at least the past 20 years in order to support those interruptions.

In conclusion, Mr. Dauphinais testified the core of Rider 675 is essentially the same as Rider 581 in Cause No. 43526, with the difference being in the options it provides to allow potential interruptible customers to tailor the combination of curtailment requirements, interruption requirements and compensation that works best for them consistent with past suggestions of the Commission. He said the compensation provided under each of these options is commensurate with the curtailment and interruption obligations and that Rider 675 under the Settlement is reasonable in the context of the overall Settlement. He emphasized Rider 675 is a fundamental and critical component to the Settlement that provides large industrial customers, the rate class taking the largest percentage base rate increase under the Settlement, a reasonable opportunity to mitigate the increase. Mr. Dauphinais said he continues to recommend that the Commission accept the Settlement in its entirety.

11. Commission Discussion and Findings. Settlements presented to the Commission are not ordinary contracts between private parties. *United States Gypsum, Inc. v. Indiana Gas Co.*, 735 N.E.2d 790, 803 (Ind. 2000). Any settlement agreement that is approved by the Commission "loses its status as a strictly private contract and takes on a public interest gloss." *Id.* (quoting *Citizens Action Coalition v. PSI Energy, Inc.*, 664 N.E.2d 401, 406 (Ind. Ct. App. 1996)). Thus, the Commission "may not accept a settlement merely because the private parties are satisfied; rather [the Commission] must consider whether the public interest will be served by accepting the settlement." *Citizens Action Coalition*, 664 N.E.2d at 406. Furthermore, any Commission decision, ruling or order - including the approval of a settlement - must be supported by specific findings of fact and sufficient evidence. *United States Gypsum*, 735 N.E.2d at 795 (citing *Citizens Action Coalition v. Public Service Co.*, 582 N.E.2d 330, 331 (Ind. 1991)). Therefore, before the Commission can approve the Settlement, we must determine whether the evidence in this Cause sufficiently supports the conclusion that the Settlement is reasonable, just, and consistent with the purpose of Ind. Code ch. 8-1-2, and that such Settlement serves the public interest. We will discuss the major components of the Settlement.

We have previously discussed our policy with respect to settlements:

> Indiana law strongly favors settlement as a means of resolving contested proceedings. *See, e.g., Manns v. State Department of Highways*, 541 N.E.2d 929, 932 (Ind. 1989); *Klebes* v. *Forest Lake Corp.,* 607 N.E.2d 978, 982 (Ind. Ct. App. 1993); *Harding* v. *State*, 603 N.E.2d 176, 179 (Ind. Ct. App. 1992). A settlement agreement "may be adopted as a resolution *on the merits* if [the Commission] makes an independent finding supported by 'substantial evidence on the record as

a whole' that the proposal will establish 'just and reasonable' rates." *Mobil Oil Corp.* v. *FPC*, 417 U.S. 283, 314 (1974) (emphasis in original).

See, e.g., Indianapolis Power & Light Co., Cause No. 39938, at 7 (IURC 8/24/95); *Commission Investigation of Northern Ind. Pub. Serv. Co.*, Cause No. 41746, at 23 (IURC 9/23/02). This policy is consistent with expressions to the same effect by the Supreme Court of Indiana. *See, e.g., Mendenhall v. Skinner & Broadbent Co.*, 728 N.E.2d 140, 145 (Ind. 2000) ("The policy of the law generally is to discourage litigation and encourage negotiation and settlement of disputes.") (citation omitted); *In re Assignment of Courtrooms, Judge's Offices and Other Facilities of St. Joseph Superior Court*, 715 N.E.2d 372, 376 (Ind. 1999) ("Without question, state judicial policy strongly favors settlement of disputes over litigation.") (citations omitted). Furthermore, we are mindful regarding a settlement which has been entered by representatives of all customer classes, including OUCC (who represents all ratepayers), even though there may be some intervenor or group of intervenors who opposes it. *American Suburban Utils.,* Cause No. 41254, at 4-5 (IURC 4/14/99).

A. Revenue Requirement. The Settlement provides for an agreed-upon revenue requirement that reflects the following original cost rate base, cost of capital and financial results which the Settling Parties agree are reasonable for purposes of compromise and settlement:

Indiana Jurisdictional Rate Base as of June 30, 2010
(000)

Electric Plant In Service	$5,636,770,407
Common Allocated	$207,518,424
Less: Disallowed Plant, Unit 17	$31,733,655
Total Utility Plant	$5,812,555,176
Accumulated Depreciation and Amortization	$(3,165,301,803)
Common Allocated	$(96,045,375)
Less Disallowed Plant: Unit 17	$(30,239,815)
Total Accumulated Depreciation and Amortization	$(3,231,107,364)
Net Utility Plant	$2,581,447,813
Unit 17 Depreciation	$0
Unit 18 Depreciation	$3,277,484
Unit 18 Carrying Charges	$10,132,193

Materials & Supplies	$58,224,978
Production Fuel	$52,823,583
Total Rate Base	$2,705,906,051

Capital Structure as of June 30, 2010

	Balance (000)	% of Total	Cost	WACC
Common Equity	$1,470,831,844	46.53%	10.20%	4.75%
Long-Term Debt	$1,025,792,388	32.46%	6.42%	2.08%
Customer Deposits	$73,318,625	2.32%	4.43%	0.10%
Deferred Income Taxes	$426,048,518	13.48%	0.00%	0.00%
Post-Retirement Liability	$147,029,052	4.65%	0.00%	0.00%
Post-1970 ITC	$17,636,467	0.56%	8.65%	0.05%
Totals	$3,160,656,894	100.0%		6.98%

Pro Forma Proposed Rates

Operating Revenues	$1,401,000,000
Fuel, Purchased Power	$474,458,056
Operating Expenses	
Operations & Maintenance	$363,237,597
Depreciation	$190,392,968
Amortization Expense	$36,500,530
Taxes	$147,538,607
Total Operating Expenses	$737,669,702

Net Operating Income $188,872,242

No other party to this proceeding has provided any evidence, including evidence opposing the Settling Parties' proposal, with regard to Petitioner's Rate Base, Rate of Return, Operating Income, or Revenue Requirement. The Commission finds that the Petitioner's rate base and rate of return, as agreed to by the Settling Parties, is supported by substantial evidence of record. In addition, we find the proposed depreciation expense and depreciation rates, as supported by Mr. Spanos, are supported by substantial evidence of record. Further, we find the proposed amortization of the rate case expense, deferred MISO costs and the Sugar Creek deferred depreciation and carrying costs, as agreed to by the Settling Parties, is supported by substantial evidence of record. Finally, we find the revenue requirement, as agreed to by the Settling Parties, is supported by substantial evidence of record.

B. Revenue Allocation. While NIPSCO presented a cost of service study prepared by Dr. Gaske, the utility proposed an across-the-board allocation of its requested revenue increase above pro forma adjusted test year revenues. The Settling Parties chose to allocate revenue by class in a manner designed to mitigate the level of increase to any one customer class. As noted by Mr. Shambo, no customer class, other than large industrials, will see an increase to its base rate revenue allocation in excess of 12 percent. We are cognizant of NIPSCO's managerial decision to discontinue the use of special contracts, and that the expiration of those contracts effectively imposes a substantial increase in rates on its energy intensive industrial customers. Given the diverse nature of the Settling Parties, and their willingness to agree to the proposed allocation of revenue, and given that no party to this proceeding provided evidence in opposition to the proposed allocation of revenue, we find that the proposed allocation of revenue is supported by substantial evidence of record and is appropriate for development of NIPSCO's retail rates and charges.

Hammond raised a variety of arguments regarding the revenue allocation method contained in the Settlement in its Exceptions, but Hammond presented no evidence that the proposed revenue allocation was not reasonable, lawful or in the public interest. The Indiana Court of Appeals has found that the Commission need not make a finding regarding cost of service. *Bethlehem Steel v. Northern Ind. Pub. Serv. Co.,* 397 N.E. 2d 623, 633 (Ind. Ct. App. 1997). The Commission has approved rates that were not strictly based on a cost of service study. *See Northern Ind. Pub. Serv. Co.*, Cause No. 38045 (IURC 7/15/87); *Board of Directors for Utils. of the Dep't of Pub. Utils. of the City of Indianapolis*, Cause No. 39066 (IURC 11/1/91); Cause No. 42767 (IURC 10/19/06); Cause No. 43463 (IURC 9/17/08); *Northern Ind. Pub. Serv. Co.*, Cause No. 43984 (IURC 11/4/10). Several cost of service studies were presented to the Commission and showed a variety of outcomes. As discussed by Mr. Bolinger, the revenue requirement, revenue allocation and Rider 675 were interrelated and reflected difficult and painstaking negotiations to reach a balanced outcome and resolution which was acceptable to the Settling Parties.

The determination of NIPSCO's true cost of service for each rate class is complicated by a number of factors, including a substantial amount of interruptible load, disagreement over the allocation methodology (i.e., 12 CP, 4CP, Peak and Average) and the migration of customers from special contracts to firm service. NIPSCO's ACOSS, which was provided to the stakeholders for transparency purposes, created additional complications due to the judgments that were made in migrating customers to rates that were not yet in effect, and assigning revenues based on those migrations without accounting for other changes in customer behavior that could occur based on the revised pricing structures. Accordingly, in its case-in-chief, NIPSCO proposed an equal percentage increase to all customer classes, after adjustments, as an attempt to simplify the rate impacts on the individual customer classes. The Settlement takes that approach one step farther, and modifies the across-the-board increase and attempts to tailor the increases through negotiations with parties.

Revenue allocation was one of the most contentious issues in this case, and in Cause No. 43526. Although not all parties were signatories to the Settlement, the Settling Parties respectively represent every customer class, and negotiated the allocation of costs or revenues to the respective classes. Accordingly, we give substantial weight to the Settling Parties' agreement with respect to revenue allocation. We find that the Settlement revenue allocation constitutes just and reasonable rates under Ind. Code § 8-1-2-4. However, we order NIPSCO, in its next rate case filing, to base its proposed rates on a cost of service analysis.

C. Rate Design. The Commission will first address the contested areas of rate design and then address those areas that were not contested. As we do so, we note the admonition and direction we provided to NIPSCO in Cause No. 43526 regarding the need for collaboration with its largest customers:

> Finally, we must note that despite NIPSCO's assertion to the contrary, it is not evident that NIPSCO endeavored to develop tariff provisions that responded to the requirements of its large industrial customers, to the extent reasonably possible. We were troubled by [NIPSCO's] statement on the first day of the evidentiary hearing that the rate case filing represented the opening round of negotiations between NIPSCO and its industrial customers concerning its new tariff rates. To the Commission, such remarks indicate callous indifference to concerns of a majority of its load and demonstrate a poor management decision. In the absence of special contracts, we would encourage NIPSCO to continue discussions with its industrial customers to develop tariffs that are more narrowly tailored to its industrial customers' needs while furthering NIPSCO interests, resulting in a win-win scenario for both sides.

43526 Order at 113. We have heard considerable evidence concerning the collaborative effort among NIPSCO and representatives of all customer classes to reach accord on all issues in this case, including the development of service structure, tariff provisions and rate design that respond to the needs of the industrial customers. We must keep this level of collaboration in mind as we review the Settlement, especially when it is precisely the type of effort we directed in the 43526 Order.

(a) Rider 675. As explained by several witnesses, Rider 675 is an interruptible service that provides large industrial customers with various options with regard to various amounts of interruptions, on various notice, and various amounts of curtailment and interruptions. This interruptible service allows certain large industrials to mitigate large increases due to termination of special contracts and the elimination of Rates 836 and 845 with concurrent benefits to all customers in the form of avoided capital costs for additional generation and lower fuel costs flowing through the FAC.

We begin our discussion of Rider 675 by comparing it to what was proposed and what was ultimately authorized in Cause No. 43526. There, NIPSCO proposed one category of interruptible service, capped at 250 MW, interruptible or curtailable on 10 minutes' notice, and requiring a 3-year contract. On rebuttal, NIPSCO accepted the proposals of the Industrial Group to increase the amount of interruptible service to 500 MW, to extend the notice requirement to 4 hours, and to provide a demand credit of $6.75 per KW, for a total cap of $40.5 million. We authorized Rider 581 over the Industrial Group's opposition to the single category of service, which mandated interruption for economic purposes. We explained: "[Industrial Group] promoted a construct whereby Rider 581 customers are paying at interruptible rates for nearly firm service." 43526 Order at 114.

The Settlement provides for interruptible service that is based upon what we authorized in Cause No. 43526, keeping the maximum at 500 MWs, but also reducing the total annual cap to $38 million (from $40.5 million approved in Cause No. 43526). The proposed Rider 675 differs from the rider approved in Cause No. 43526 by now providing for four categories of service in an effort to "respond[] to the requirements of [NIPSCO's] large industrial customers . . . to develop tariffs that are more narrowly tailored to [NIPSCO's] industrial customers' needs." *Id.* at 113. These options also serve to address the Commission's concerns regarding economic interruption noted above. Option A responds to the chief objection of the Industrial Group to Rider 581's mandated interruption for economic reasons by eliminating economic interruptions. It also has a much shorter contract term (1 year versus 3 years). In view of these changes, this option offers a lower credit value ($1 versus $6.75), which will be continually adjusted to match the market for short-term capacity. We consider the reduced credit to be reasonable for short-term, reliability only curtailments. Option B is most like the interruptible service we authorized in Cause No. 43526. A three-year contract is required, 4-hours' notice is provided, interruptions for economic reasons are permitted, and the credit is slightly reduced below the level we approved ($6 versus $6.75). Option C is more valuable ($8 credit) than the rate we approved in Cause No. 43526, requiring a 7-year contract term (as compared to 3 years), unlimited duration of curtailments and providing for interruptions or curtailments on one-hour notice. This shorter notice to perform approximates the startup time required for NIPSCO's existing combustion turbine units. Option D requires a 10-year term and interruptions or curtailments on 10 minutes' notice. This category most closely resembles the currently effective Rate 836, and the proposed credit of $9 is less than the approximately $13 credit incorporated into Rate 836.

Hammond invites the Commission to delay deciding the reasonableness of the Settling Parties' proposal in this proceeding and instead to turn every subsequent FAC and RA Tracker proceeding into a prudence review of NIPSCO's contracts, which would be entered into pursuant to Rider 675. Such a result would introduce an untenable level of risk to the FAC and other tracker proceedings.

The decision regarding the prudency of Rider 675 should be made in this proceeding, not reserved for tracker proceedings that already require review of myriad factors beyond cost of fuel. Use of Rider 675 protects all of NIPSCO's customers by potentially avoiding the costs to build new generation that would be ultimately recovered through base rates and the higher energy costs that would need to be paid if NIPSCO could not curtail demand during times of high energy prices or peak usage. At the same time, Rider 675 protects NIPSCO from not recovering reasonably incurred costs through its basic rates and charges. Rider 675 also provides the opportunity for NIPSCO's customers who have invested for interruptibility in their operations to receive credit from firm service customers. Absent a cost-of-service study that accounts for the true cost for NIPSCO to provide interruptible service, Rider 675 provides a reasonable basis for interruptible customers to benefit from the ability to be interrupted. Further, the cap on total dollar amounts and energy available under Rider 675 protects firm service customers from overexposure to interruptible cost. Finally, although the 500 MWs of capacity may exceed NIPSCO's historic interruptible load, we believe that Rider 675 will provide a longer term solution than if the capacity limit of the rider were set at a level consistent with recent load data. Obviously, if neither capacity nor dollar levels expand to the limits of Rider 675, firm service customers will not pay for unused capacity under the rider.

Based upon the evidence presented, the Commission finds that the Settling Parties' proposed Rider 675, including its four options for interruptible service, is reasonable and should be approved. In addition, we find that the Settling Parties' proposed cap of $38 million for credits and/or 500 MWs of capacity are reasonable and should also be approved.

(b) Rate 611. The Settling Parties have agreed that the Customer Charge for Rate 611 should be $11/month and that there should be one block of energy usage. Mr. Cearley recommended that the increase to those customers using minimal amounts of energy would be lessened if NIPSCO instituted an inclining block rate. As noted by Mr. Shambo, the primary cause for the differential in the percentage increase is driven by the increase in the customer charge from $5.95/month to $11/month. In the 43526 Order, we found that NIPSCO had presented sufficient evidence to support its customer charge and single block rate design. In this proceeding, Mr. Cearley presented no probative evidence disputing this finding.

Based upon our review of the evidence, we find that Rate 611, as proposed in the Settlement, is reasonable and should be approved.

(c) Rule 10.2. The Settling Parties have agreed to a revised rule for non-residential customers' deposits. Hammond witness Mr. Cearley proposed that the Rule be revised to provide that NIPSCO will annually credit accrued interest from its non-residential customers to its non-residential customers' bills. No precedent for this proposal was cited, nor was any rationale provided for requiring NIPSCO to undertake such an effort when no other utility in Indiana is required to do so. However, Mr. Westerhausen stated during cross-examination that NIPSCO could credit non-residential customers' bills with accrued interest upon the customer's request. We find that there is sufficient evidence to approve Rule 10.2 as presented in the Settlement, with the qualification that annually, upon a customer's request, NIPSCO would credit any accrued interest to the customer's bill.

(d) RA Tracker. The RA Tracker is a semi-annual tracking mechanism coordinated with the FAC audit process, that recovers prudently incurred capacity costs and 75 percent of costs associated with any credits paid as a result of Rider 675. The allocators for the RA Tracker are set forth in Joint Exhibit E to the Settlement, and will be revised to reflect MWs of interruptible service taken by class. Hammond witness Mr. Cearley disputed the amount of the credits payable under Rider 675, but no party offered evidence in opposition to recovery of 75 percent of the costs associated with any credits for Rider 675, nor did any party offer evidence opposing the allocation of the costs to be recovered by the RA Tracker. We find that there is sufficient evidence to approve the RA Tracker as presented in the Settlement. Due to the lag between payment and recovery of credits, the actual amount of credits paid will be deferred in a balance sheet account until they are recovered in the RA Tracker, or in the case of the 25% portion, in the FAC.

(e) Uncontested Rate Design Issues. Joint Exhibit D to the Settlement provides a summary of the changes agreed to by the Settling Parties regarding various Rates, and the Commission finds that substantial evidence of record exists to support the proposed Rates. Joint Exhibit G is Rider 676, agreed to in the Settlement. No party disputed the Rider 676 terms and the Commission finds that substantial evidence exists to support Rider 676. The RTO Tracker approved in Cause No. 43526 will also be implemented with the basic rates and charges approved in this Cause. The RTO Tracker is a semi-annual mechanism coordinated with the FAC audit process that will recover MISO non-fuel costs and revenues that exceed $5.3 million annually or $2.65 million semi-annually (the amount of MISO non-fuel credits and charges included in base rates) and 50% of any off system sales margins that exceed $7.6 million annually (the amount of off-system sales margins included in base rates). The Settlement is silent as to the allocation of costs in the ECRM and EERM and the Settlement does not preclude the Commission from deciding the proper allocation in a subsequent proceeding. Therefore, for purposes of its compliance filing in this proceeding, NIPSCO should allocate costs for the ECRM and EERM consistent with the way it is currently allocating them, and the Commission finds that in its first ECRM and EERM following issuance of this Order (to be filed in February 2012), NIPSCO shall propose an allocation methodology, which all parties are free to contest.

(f) Uncontested Rules. The Settling Parties presented proposed Rules, identified as Petitioner's Exhibit CAW-S2, which the Commission finds are supported by substantial evidence of record and shall be approved.

D. Summary. The Commission has carefully analyzed the evidence and the proposed Settlement, and finds that the resulting rates are reasonable and just and properly balance the interests of NIPSCO, its customers and the overall public interest. Mr. Shambo testified that NIPSCO had as many as 50 meetings with its stakeholders to reach resolution of this matter. Mr. Bolinger testified as to the painstaking negotiations that were held to resolve this complex litigation. While the Commission has expressed its policy goal of moving rates towards a cost of service basis, as noted by Mr. Bolinger, the return from any rate class is calculated consistent with either a 4 CP study, a 12 CP study, or upon a peak and average methodology. While no cost of service study was presented utilizing the agreed upon revenue allocation, NIPSCO's direct testimony did provide both a 4 CP and a 12 CP cost of service study.

In reviewing the rate structure proposed by the Settling Parties, the Commission is guided by Ind. Code § 8-1-2-4 which establishes:

> The charge made by any public utility for any service rendered or to be rendered either directly or in connection therewith shall be reasonable and just . . . .

The Indiana Court of Appeals has found that the Commission need not make a finding regarding cost of service. *See*, *Bethlehem Steel Corp. v. Northern Indiana Pub. Serv. Co.*, 397 N.E.2d 623 at 633 (Ind. Ct. App. 1979). The Court went on to state:

> Although cost of service may be a factor the Commission could usefully consider in determining the rate design, it is not error for the Commission not to determine the cost of service in its findings. *See, e.g.*, *Boone County Rural Electric Membership Corp. v. Public Service Commission*, 239 Ind. 525, 159 N.E.2d 121 (1959); *Public Service Commission v. City of Indianapolis*, 235 Ind. 70 at 95, 131 N.E.2d at 318 (1956); *Public Service Commission v. Indiana Bell Telephone Co.*, 235 Ind. 1, 130 N.E.2d 467 (1956); *Capital Improvement Board of Managers v. Public Service Commission*, 176 Ind. App. 240, 375 N.E.2d 616 (1978); *L. S. Ayres & Co. v. Indianapolis Power & Light Co.*, 169 Ind. App. 652, 351 N.E.2d 814 (1976).

Id. at 633-634. As shown by substantial evidence of record, the Settlement provides a just and reasonable resolution of all matters pending before the Commission in this case. It reflects the significant collaboration and compromise inherent in serious negotiations among a diverse group of interests. While the Settlement is reasonable as a whole, the evidence in support of the Settlement explains the basis for the proposed rates and other included elements. As a result, the Commission is able to understand how each disputed issue was resolved and to determine that the Settlement is amply supported by the evidence of record, and we so find.

Additionally, as noted above, public policy favor settlements. This public policy is part of the overall public interest. Hence, in the context of settlement, the public interest appropriately includes consideration of the compromise inherent in the negotiation process, particularly where, as here, the Settlement results from a rigorous process and presents a balanced and comprehensive resolution of all the issues among most of the parties. The Commission is particularly mindful of the impact of its decisions. The disparate interests of the Settling Parties provide the Commission some assurance that the interests of all customers have been considered by the Settling Parties. Based upon the evidence of record in this proceeding, the Commission finds that the Settlement is reasonable and in the public interest and should be approved. We further find that the new proposed IURC Electric Service Tariff, Original Volume No. 12, including, but not limited to, the rates and charges set forth therein, is fair, just and reasonable and should be approved subject to the terms and conditions contained in the Settlement. The Commission further finds that for purposes of the earnings test component of the FAC, Petitioner's authorized annual net operating income shall be $188.9 million.

The Settling Parties agreed that the Settlement shall not constitute an admission or a waiver of any position that any of the Settling Parties may take with respect to any or all of the items and issues resolved therein in any future regulatory or other proceedings, except to the extent necessary to enforce its terms. However, with regard to future citation of the Settlement, we find the Settlement and our approval of it should be treated in a manner consistent with our finding in *Richmond Power & Light,* Cause No. 40434 (IURC 3/19/97).

E. Compliance Filing in Cause No. 43526. On April 25, 2011, the Presiding Officers issued a Docket Entry staying the consideration of the Compliance Filing made under

Cause No. 43526 pending an Order in this Cause. The rates proposed in this Cause supersede the rates proposed in Cause No. 43526, and as such, the Compliance Filing in Cause No. 43526 is moot.

12. <u>Confidentiality</u>. NIPSCO filed a motion for protective order and NIPSCO and Industrial Group filed a joint motion for protective order, both of which were supported by affidavits showing documents to be submitted to the Commission were trade secret information within the scope of Ind. Code §§ 5-14-3-4(a)(4) and (9) and Ind. Code § 24-2-3-2. The Presiding Officers issued a Docket Entry finding the information described in NIPSCO's first request to be preliminarily confidential, after which such information was submitted under seal. The information subject to the joint motion was submitted under seal after the presiding officer granted the joint motion on the record. In its Brief, Hammond contests the Commission's preliminary finding of confidentiality with regard to exhibits Hammond CS-48 Confidential, Hammond CS-49 Confidential and related *in camera* testimony, all of which contained specific customer information. Hammond did not appeal the Presiding Officer's decision at the hearing to the full Commission, and thus has waived its opportunity to challenge the ruling. *See* 170 IAC 1-1.1-25(b) (appeals of oral rulings must be made immediately following the ruling). Further, Hammond presented no contradictory evidence at the hearing to suggest that the Commission's preliminary determination should be reversed. Accordingly, we find 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. The Stipulation and Settlement Agreement between Petitioner, OUCC and various Intervenors filed in this Cause on July 18, 2011, and attached hereto, shall be and hereby is accepted, approved and adopted by the Commission.

2. The proposed IURC Electric Service Tariff, Original Volume No. 12 as filed on July 22, 2011, is approved and shall be effective upon its filing and approval with the Commission's Electricity Division.

3. The depreciation accrual rates set forth in Petitioner's Exhibit No. JJS-2 shall be and hereby are approved.

4. Base rates in this case reflect an annual credit of approximately $3.9 million due to sales from emission allowances. This annual credit will remain in base rates for a period of three years and at the end of the three year period, Petitioner shall adjust its base rates to reflect the elimination of this credit.

5. Petitioner shall adjust its base rates to reflect the elimination of the amortization expense for rate case costs, Sugar Creek deferred depreciation and carrying charges, and the MISO deferred costs at the end of the respective amortization periods approved herein by filing revised rate schedules with the Commission's Electricity Division.

6. The information submitted under seal in this Cause pursuant to motions for protective orders is determined to be confidential and exempt from public access and disclosure pursuant to Ind. Code § 24-2-3-2 and § 5-14-3-4.

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

BENNETT, LANDIS, MAYS AND ZIEGNER CONCUR; ATTERHOLT ABSENT:

APPROVED: DEC 21 2011

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

OFFICIAL EXHIBITS

IURC JOINT EXHIBIT No. 1
4-12-11
DATE REPORTER

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY ("NIPSCO") FOR (1) AUTHORITY TO MODIFY ITS RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE; (2) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES APPLICABLE THERETO; (3) APPROVAL OF REVISED DEPRECIATION ACCRUAL RATES; (4) INCLUSION IN ITS BASIC RATES AND CHARGES OF THE COSTS ASSOCIATED WITH CERTAIN PREVIOUSLY APPROVED QUALIFIED POLLUTION CONTROL PROPERTY PROJECTS; AND (5) APPROVAL OF VARIOUS CHANGES TO NIPSCO'S ELECTRIC SERVICE TARIFF INCLUDING WITH RESPECT TO THE GENERAL RULES AND REGULATIONS.	)	CAUSE NO.: 43969

STIPULATION AND SETTLEMENT AGREEMENT

This Stipulation and Settlement Agreement ("Agreement") is entered into as of the 18th day of July, 2011, by and between Northern Indiana Public Service Company ("NIPSCO" or "Company"), the Indiana Office of Utility Consumer Counselor ("OUCC"), the NIPSCO Industrial Group ("Industrials"), NLMK Indiana f/k/a Beta Steel Corporation ("NLMK") and the Indiana Municipal Utilities Group ("Municipals") (collectively the "Settling Parties"), who stipulate and agree for purposes of settling the issues in this Cause that the terms and conditions set forth below represent a fair and reasonable resolution of all issues subject to incorporation into a Final Order of the Indiana Utility Regulatory Commission ("Commission") without any modification or condition that is not acceptable to the Settling Parties.

A. Background.

1. <u>NIPSCO's Current Base Rates and Charges</u>. NIPSCO's currently effective rates and charges for electric utility service were established pursuant to the Commission's Order dated July 15, 1987 in Cause No. 38045. The Commission issued an Order in Cause No.

43526 on August 25, 2010 ("August 25 Order"), which authorized the modification to NIPSCO's rates and charges for electric service. On April 25, 2011 the Commission issued a docket entry granting the Joint Motion to Vacate Remainder of Procedural Schedule in the Compliance Phase, filed by NIPSCO, the OUCC, the City of Hammond and the LaPorte County Board of Commissioners, and suspending the Compliance Filing Schedule. Consequently, the resulting rates have not yet been implemented.

2. NIPSCO's Current Depreciation Accrual Rates. The August 25 Order also approved new depreciation accrual rates; however, as confirmed by the Docket Entry issued in Cause No. 43526 on October 22, 2010, those new depreciation accrual rates will not take effect until new rates and charges take effect. As a result, NIPSCO's currently effective depreciation accrual rates for its electric and common properties were based on a depreciation study prepared in its general rate proceeding in Cause No. 38045.

3. NIPSCO's Fuel Adjustment Clause ("FAC") Proceedings. NIPSCO files a quarterly FAC proceeding in accordance with Ind. Code § 8-1-2-42(d) under Cause No. 38706-FAC-XX to adjust its rates to account for fluctuations in its fuel costs.

4. NIPSCO's Tracking Mechanisms. In Cause No. 42150, the Commission approved two tracking mechanisms for NIPSCO that recover costs associated with Qualified Pollution Control Property ("QPCP") and Clean Coal Technology ("CCT"). Since those approvals, NIPSCO has been recovering a return on its investment in approved QPCP/CCT projects and depreciation expense and operation and maintenance expense relating thereto through its Environmental Cost Recovery Mechanism ("ECRM") and its Environmental Expense Recovery Mechanism ("EERM").

The Commission has also approved three other semi-annual tracking mechanisms:

(a) the Demand Side Management Adjustment Mechanism ("DSMA"), approved by the Commission in Cause No. 43618 that recovers annual costs applicable to NIPSCO's Demand Side Management programs;

(b) the Regional Transmission Organization ("RTO Tracker") approved by the Commission in Cause No. 43526 that recovers net non-fuel Midwest Independent Transmission System Operator, Inc. costs and provides a 50/50 sharing mechanism of annual off-system sale margins above $7,600,638.

(c) the Resource Adequacy ("RA Tracker") approved by the Commission in Cause No. 43526 that recovers the cost of capacity purchases and credits paid for interruptible load.

5. <u>This Proceeding</u>. On November 19, 2010, NIPSCO filed with the Commission its Verified Petition to modify its rates and charges for electric utility service, for approval of new schedules of rates and charges applicable thereto, for approval of revised depreciation accrual rates; for inclusion in its basic rates and charges of the costs associated with certain previously approved QPCP projects; and for approval of certain other requests. NIPSCO also filed its prepared testimony and exhibits constituting its case-in-chief on November 19, 2010. A Prehearing Conference and Preliminary Hearing was conducted on December 17, 2010 and a Prehearing Conference Order was issued on January 5, 2011. A subsequent Docket Entry, issued April 4, 2011 modified the procedural schedule. An evidentiary hearing was held on February 28 through March 4, 2011 and May 16 through 18, 2011 on NIPSCO's Case-in-Chief.

B. Settlement Terms.

6. Revenue Requirement and Net Operating Income.

(a) Revenue Requirement.

The Settling Parties agree that NIPSCO's base rates will be designed to produce $1.355 billion, which is the Revenue Requirement of $1.401 billion less $46 million of Other Revenues. This Revenue Requirement is a decrease of $68 million from the amount originally requested by the Company. Based on test-year fuel costs, this provides for a margin requirement of $927 million plus $12 million in non-trackable fuel.

(b) Net Operating Income.

The Settling Parties agree that NIPSCO's Revenue Requirement in Paragraph B.6.(a) results in a proposed authorized net operating income ("NOI") of $188.9 million.

7. Fair Value Rate Base, Capital Structure and Fair Return.

(a) Fair Value Rate Base

NIPSCO has agreed that its weighted cost of capital times its original cost rate base yields a fair return for purposes of this case. Based upon this agreement, the Settling Parties concur that NIPSCO should be authorized a fair rate of return of 6.98%, yielding an overall return for earnings test purposes of $188.9 million, based upon:

(i) an original cost rate base of $2.7 billion, inclusive of materials, supplies and production fuel, as proposed in NIPSCO's case-in-chief;

(ii) NIPSCO's capital structure; and

(iii) an authorized return on equity ("ROE") of 10.2%.

NIPSCO's sum of the differentials, commonly referred to as the "earnings bank" computed under Ind. Code § 8-1-2-42.3, shall be re-set to $200 million.

(b) Capital Structure and Fair Return.

Based on the following capital structure, the 10.2% ROE and cost of debt/zero cost capital as filed, the overall weighted average cost of capital is computed as follows:

	% of Total	Cost	WACC
Common Equity	46.53%	10.20%	4.75%
Long-Term Debt	32.46%	6.42%	2.08%
Customer Deposits	2.32%	4.43%	0.10%
Deferred Income Taxes	13.48%	0.00%	0.00%
Post-Retirement Liability	4.65%	0.00%	0.00%
Post-1970 ITC	0.56%	8.65%	0.05%
Totals	100.0%		6.98%

(c) Environmental Project Financing.

The Settling Parties agree that NIPSCO should finance, in aggregate, the projects for which it receives a Certificate of Public Convenience and Necessity in Cause No. 44012 with at least 60% debt capital.

8. Depreciation and Amortization Expense.

(a) Depreciation Expense.

The Settling Parties stipulate that the depreciation accrual rates recommended by NIPSCO Witness John Spanos and presented in this proceeding (the "Depreciation Study") should be approved, except that pro-forma depreciation expense should be reduced by $4.9 million due to proposed changes to the net salvage percents for steam production, station equipment, and distribution poles. Joint Exhibit A contains a spreadsheet showing the proposed depreciation rates by class of property.

(b) Amortization Expense.

The Settling Parties stipulate that annual amortization expense shall be $36.5 million that includes amortization of software and the following items:

(i) Rate case expenses of $0.770 million for this case amortized over a period of three (3) years. After the completion of the three (3) year period, NIPSCO agrees to make a tariff filing that will reflect the reduction in amortization expense.

(ii) Deferred MISO costs, amortized and recovered over a period of four (4) years. Amounts included in this case were estimated through June 30, 2011. Costs will continue to be deferred until the effective date of new rates. Any difference between the estimate and the actual costs incurred will be included in the RTO tracker approved in Cause No. 43526.

(iii) Deferred Sugar Creek depreciation and carrying charges, through June 30, 2011, amortized and recovered over five (5) years. The Settling Parties agree that Sugar Creek depreciation and carrying charges may continue to be deferred from July 1, 2011 through December 31, 2011 or the implementation of new basic rates and charges, whichever occurs earlier. These amounts will remain as a regulatory asset on NIPSCO's books and records, but shall accrue no additional carrying charges, and NIPSCO may request recovery of the deferred amount in NIPSCO's next general rate case; provided the other Settling Parties reserve the right to contest the recovery of those amounts.

9. Operating Results at Current and Proposed Rates. Joint Exhibit B contains a Statement of Operating Income for the twelve months ended June 30, 2010 shown on an actual basis, and with pro forma adjustments at current and proposed rates per NIPSCO's filed request and to reflect the provisions of this Agreement.

10. Cost Allocation and Rate Design. The Settling Parties agree that rates should be designed in order to allocate the revenue requirement to and among NIPSCO's customer classes in a fair and reasonable manner. For settlement purposes, the Settling Parties agree that NIPSCO should generally design its rates using the structure of its existing 800 Series tariffs.

The Settling Parties agree that NIPSCO's settlement base rates in total will be designed to produce $1.355 billion. Attached to this Agreement as Joint Exhibit C is a table that contains the allocation revenue and percentages to the various customer classes. The Settling Parties agree to the rate design specifics summarized in Joint Exhibit D.

The Settling Parties agree that the cost allocation herein results in fair and reasonable rates and charges.

11. Demand Allocators. The Settling Parties agree that NIPSCO's demand allocators for purposes of the RTO Tracker and RA Tracker are set forth in Table 1 of Joint Exhibit E. The demand allocators for purposes of the RA Tracker will be based upon those set forth in Joint Exhibit E modified to reflect the amount of interruptible load contained in Rates

632, 633 and 634.

12. ECRM and EERM Factors. The ECRM and EERM factors are approved after the expenditures have occurred, and therefore, the Settling Parties agree that the O&M and depreciation expense on the projects being added to rate base in this proceeding will continue to be deferred until the effective date of the rates, and all such deferred costs will be recovered in the appropriate EERM filing.

13. Interruptible Credit. The Settling Parties agree that NIPSCO should be authorized to implement Rider 675, which is attached hereto as Joint Exhibit F and that the credits paid under the provisions of Rider 675 should be recovered from ratepayers, with 75% of the costs recovered through NIPSCO's RA Tracker as the demand component and 25% of the costs recovered through NIPSCO's FAC mechanism as the energy component. The Settling Parties further agree that the limit on megawatt ("MW") eligibility should be 500 MW, and the maximum amount to be paid in any calendar year under Rider 675 is $38 million.

14. Temporary, Backup and Maintenance Service. The Settling Parties agree that NIPSCO should be authorized to implement Rider 676, which is attached hereto as Joint Exhibit G.

15. The Settling Parties agree that those facilities being served under Rate 832 on June 30, 2010; facilities which would have been eligible for Rate 832 on June 30, 2010, but for being on a Special Contract or on Rate 845; or facilities located behind the meter of a facility eligible under Rate 832 and which facility would have been eligible under Rate 832 are grandfathered into Rate 632 and those facilities shall remain eligible for Rate Schedule 632, regardless of any change in name, or ownership, or operation.

16. The Settling Parties agree that a voltage adjusted FAC may be appropriate, and the Parties agree to work together to determine the appropriate mechanism to be implemented. Upon reaching a resolution of that issue, the Parties will file a separate petition with the Commission.

17. Accounting Reporting. NIPSCO agrees to file separate gas and electric income statements with the Commission annually by April based on the previous calendar year. NIPSCO agrees to insure that its financial reports are transparent and verifiable for future OUCC financial audits. NIPSCO agrees to work cooperatively with the OUCC to facilitate the auditing function.

18. OUCC Audits. NIPSCO agreed in Cause No. 38706-FAC71S1 to fund the OUCC actual audit or consulting fees up to an annual maximum of $100,000 per year for the purpose of conducting a review and audit of NIPSCO's hedging program. NIPSCO agrees that the fees may be utilized by the OUCC to conduct reviews with respect to any management of fuel, purchased power, off-system sales, use of interruptible resources, or other tracking mechanisms.

19. General Rules and Regulations and Tariffs. The Settling Parties agree that NIPSCO will make certain modifications to the General Rules and Regulations and Tariffs initially proposed in this proceeding, and the Settling Parties will jointly submit those revised General Rules and Regulations and Tariffs in support of approval of this Agreement. Included in the General Rules and Regulations is Rule 10.2, which is attached as Joint Exhibit H.

20. <u>Final True-Up of Customer Credit</u>. Upon the effective date of new rates following the issuance of a Final Order in this proceeding, the revenue credit and the sharing mechanism approved in Cause No. 41746 will cease. After reconciliations of the revenue credit have been performed for all billed months, the final balance of any over or under credit will be included in the variance in the FAC filing that follows the final revenue credit reconciliation month and shall be specifically identified.

C. <u>Procedural Aspects and Presentation of the Agreement</u>.

21. The Settling Parties acknowledge that a significant motivation to enter into this Agreement is the expectation that, if the Commission finds the Agreement is reasonable and in the public interest, an order authorizing the increase in NIPSCO's rates and charges will be issued promptly by the Commission following such determination. The Settling Parties have spent many months reviewing data and negotiating this Agreement in an effort to eliminate time consuming and costly litigation. The Settling Parties agree to request that the Commission review the Agreement on an expedited basis and, if it finds the Agreement is reasonable and in the public interest, approve this Agreement without any material changes by December 31, 2011.

22. The Settling Parties agree to jointly present this Agreement to the Commission for its approval in this proceeding, and agree to assist and cooperate in the preparation and presentation of supplemental testimony as necessary to provide an appropriate factual basis for such approval.

23. If the Agreement is not approved in its entirety by the Commission, the Settling Parties agree that the terms herein shall not be admissible in evidence or discussed by any party

in a subsequent proceeding. Moreover, the concurrence of the Settling Parties with the terms of this Agreement is expressly predicated upon the Commission's approval of the Agreement in its entirety without any material modification or any material condition deemed unacceptable by any Party. If the Commission does not approve the Agreement in its entirety, the Agreement shall be null and void and deemed withdrawn, upon notice in writing by any Settling Party within fifteen (15) business days after the date of the Final Order that any modifications made by the Commission are unacceptable to it. In the event the Agreement is withdrawn, the Settling Parties will request that an Attorneys' Conference be convened to establish a procedural schedule for the continued litigation of this proceeding.

24. The Settling Parties agree that this Agreement and each term, condition, amount, methodology and exclusion contained herein reflects a fair, just and reasonable resolution and compromise for the purpose of settlement, and is agreed upon without prejudice to the ability of any party to propose a different term, condition, amount, methodology or exclusion in future proceedings. As set forth in the Order in *Re Petition of Richmond Power & Light*, Cause No. 40434, p. 10, the Settling Parties agree and ask the Commission to incorporate as part of its Final Order that this Agreement, or the Order approving it, not be cited as precedent by any person or deemed an admission by any party in any other proceeding except as necessary to enforce its terms before the Commission, or any court of competent jurisdiction on these particular issues. This Agreement is solely the result of compromise in the settlement process. Each of the Settling Parties hereto has entered into this Agreement solely to avoid further disputes and litigation with the attendant inconvenience and expenses.

25. The Settling Parties stipulate that the evidence of record presented in this Cause constitutes substantial evidence sufficient to support this Agreement and provide an adequate evidentiary basis upon which the Commission can make any findings of fact and conclusions of law necessary for the approval of this Agreement, as filed. The Settling Parties agree to the admission into the evidentiary record of this Agreement, along with testimony supporting it without objection.

26. The issuance of a Final Order by the Commission approving this Agreement without any material modification or further condition shall terminate all proceedings in this Cause. The relief requested in this proceeding is associated with but supersedes the relief approved in the August 25 Order, and as a result, upon the issuance of a Final Order approving this Agreement in its entirety without any material modification or further condition unacceptable to any Settling Party, the compliance filings in Cause No. 43526 are moot and no further consideration of those filings are necessary. The Settling Parties further agree to dismiss all pending requests for reconsideration and/or rehearing and all pending appeals of the Commission's August 25 Order.

27. The Settling Parties agree to jointly prepare a press release ("Joint Release") with language agreed upon by them describing the contents and nature of this Agreement, which will be jointly issued to the media. The Settling Parties may respond individually to questions from the public or media, provided that such responses are consistent with the Agreement.

28. The undersigned represent and agree that they are fully authorized to execute this Agreement on behalf of their designated clients who will be bound thereby.

29. The Settling Parties shall not appeal the agreed Final Order or any subsequent Commission order as to any portion of such order that is specifically implementing, without modification, the provisions of this Agreement and the Settling Parties shall not support any appeal of the portion of such order by a person not a party to this Agreement.

30. The provisions of this Agreement shall be enforceable by any Settling Party before the Commission or in any court of competent jurisdiction.

31. The communications and discussions during the negotiations and conferences which produced this Agreement have been conducted on the explicit understanding that they are or relate to offers of settlement and shall therefore be privileged.

ACCEPTED AND AGREED this 18th day of July, 2011.

Northern Indiana Public Service Company

Jimmy D. Staton

Indiana Office of Utility Consumer Counselor

A. David Stippler

NIPSCO Industrial Group

Bette J. Dodd

NLMK Indiana f/k/a Beta Steel Corporation

James W. Brew

Indiana Municipal Utilities Group

Anne E. Becker

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Northern Indiana Public Service Company
Calculation of Pro Forma Depreciation Expense - Electric Plant
Twelve Months Ended June 30, 2010
Revised

	Line No.	A/C	Description	Plant In Service A/C 101 & 106	D&A Rates per Study (10/19/2010)	Pro Forma D&A Expense
		B	C	D	E	F =CxD
	1		INTANGIBLE PLANT			
	2					
	3	301	ORGANIZATION	$ -	0.00%	$ -
	4	302	FRANCHISES & CONSENTS	$ 1,389	0.00%	$ -
	5	303	MISC INTANGIBLE PLANT	$ 33,932,227	0.00%	$ -
	6		TOTAL INTANG PLANT	$ 33,933,616		$ -
	7		STEAM PRODUCTION PLANT			
	8	310	LAND AND LAND RIGHTS	$ 4,985,072	0.00%	$ -
*	9	311	STRUCTS & IMPRVMNTS	$ 484,686,080	1.25%	$ 5,808,576
*	10	312.1	BOILER PLANT EQP	$ 1,469,132,524	3.25%	$ 47,746,807
	11	312.2	MOBILE FUEL HDLG/STRG	$ 18,514,564	0.00%	$ -
	12	312.3	UNIT TRAIN COAL CARS	$ 4,052,864	0.00%	$ -
*	13	312.4	S02 PLANT EQP	$ 138,284,586	4.44%	$ 6,139,836
*	14	312.5	COAL PILE BASE	$ 5,843,930	0.24%	$ 14,025
	15	313	ENGS & ENG-DRVN GENS	$ -	0.00%	$ -
*	16	314	TURBOGENERATOR UNITS	$ 462,781,231	2.64%	$ 12,217,424
*	17	315	ACCESSORY ELECTRIC EQP	$ 251,367,794	1.91%	$ 4,801,125
*	18	316	MISC PWR PLNT EQP	$ 38,607,867	1.83%	$ 706,524
	19		TOAL STEAM PROD PLANT	$ 2,858,256,512		$ 77,434,317
	20		NUCLEAR PROD PLANT			
	21	321	STRUCTS & IMPRVMNTS	$ -	0.00%	$ -
	22		TOTAL NUC PROD PLANT	$ -		$ -
	23		HYDRO PROD PLANT			
	24	330	LAND AND LAND RIGHTS	$ 23,137	0.00%	$ -
	25	331	STRUCTS & IMPRVMNTS	$ 3,007,892	6.20%	$ 186,489
	26	332	RESIVRS, DAMS, WTR WAYS	$ 6,139,608	6.53%	$ 400,916
	27	333	WTR WHLS, TURBNS, GENS	$ 4,741,205	2.73%	$ 129,435
	28	334	ACCESSORY ELECTRIC EQP	$ 1,784,733	4.09%	$ 72,996
	29	335	MISC PWR PLNT EQP	$ 79,710	1.78%	$ 1,419
	30	336	ROADS, RRS, AND BRIDGES	$ -	0.00%	$ -
	31		TOTAL HYDRO PROD PLNT	$ 15,776,285		$ 791,255
	32		OTH PROD PLANT			
	33	340	LAND AND LAND RIGHTS	$ -	0.00%	$ -
	34	341	STRUCTS & IMPRVMNTS	$ 2,229,542	0.47%	$ 10,479
	35	342	FL HLDRS, PRDCTS, & ACS	$ 9,059,763	0.06%	$ 5,436
	36	343	PRIME MOVERS	$ 26,803,190	2.22%	$ 595,031
	37	344	GENERATORS	$ 5,384,815	0.24%	$ 12,924
	38	345	ACCSRY ELECT EQP	$ 3,171,763	2.50%	$ 79,294
	39	346	MISC PWR PLNT EQP	$ 409,649	0.49%	$ 2,007
	40		TOT OTH PROD PLANT	$ 47,058,722		$ 705,170
	41		TOTAL PROD PLANT	$ 2,921,091,519		$ 78,930,743
	42		TRANSMISSION PLANT			
	43	350.1	LAND	$ 16,659,091	0.00%	$ -
	44	350.2	LAND RIGHTS	$ 11,256,804	0.55%	$ 61,912
	45	352	STRUCTS & IMPRVMNTS	$ 14,253,309	2.61%	$ 372,011
*	46	353	STATION EQP	$ 386,379,030	2.89%	$ 11,166,354
	47	354	TOWERS AND FIXTURES	$ 88,019,126	1.99%	$ 1,751,581
	48	355	POLES AND FIXTURES	$ 111,722,827	2.80%	$ 3,128,239
	49	356	OVHD CNDCTRS AND DEV	$ 134,393,946	2.30%	$ 3,091,061
	50	357	UDGRND CONDUIT	$ 213,925	0.40%	$ 856
	51	358	UDGRND CNDCTRS & DEV	$ 954,006	3.29%	$ 31,387
	52	359	ROADS AND TRAILS	$ 70,027	0.74%	$ 518
	53		TOTAL TRANSM PLANT	$ 763,922,090		$ 19,603,919
	54		DISTRIBUTION PLANT			
	55	360.1	LAND	$ 2,301,782	0.00%	$ -
	56	360.2	LAND RIGHTS	$ 691,245	1.21%	$ 8,364
	57	361	STRUCTS & IMPRVMNTS	$ 11,833,787	2.18%	$ 257,977
*	58	362	STATION EQP	$ 207,107,251	2.64%	$ 5,467,531
	59	363	STORAGE BATTERY EQP	$ -	0.00%	$ -

Northern Indiana Public Service Company
Calculation of Pro Forma Depreciation Expense - Electric Plant
Twelve Months Ended June 30, 2010
Revised

	Line No.	A/C	Description	Plant In Service A/C 101 & 106	D&A Rates per Study (10/19/2010)	Pro Forma D&A Expense
		B	C	D	E	F =CxD
*	60	364.1	CUSTOMER TRANSFORMERS STATIC	$ 35,935,640	3.07%	$ 1,103,224
*		364.2	POLES, TWRS, AND FXTRS	$ 244,737,764	4.55%	$ 11,135,568
	61	365	OVHD CNDCTRS AND DEV	$ 180,463,041	2.63%	$ 4,746,704
	62	366	UGRND CONDUIT	$ 3,986,523	1.31%	$ 52,223
	63	367	UGRND CNDCTRS & DEV	$ 231,528,430	2.60%	$ 6,019,739
	64	368	LINE TRANSFORMERS	$ 211,942,356	2.00%	$ 4,238,847
	65	369.1	OVHD SERVICES	$ 37,503,795	0.17%	$ 63,756
		369.2	UGRND SERVICES	$ 146,092,377	0.84%	$ 1,227.176
	66	370.1	CUSTOMER METERING STATIONS	$ 12,771,242	2.34%	$ 298,847
		370.2	METERS	$ 58,884,137	3.71%	$ 2,184,601
	67	371	INSTLTS ON CUST PREM	$ 7,342,216	5.95%	$ 436,862
	68	372	LSD PROP ON CUST PREM	$ -	0.00%	$ -
	69	373	STRT LGHTS & SGNL SYS	$ 36,758,790	3.02%	$ 1,110,115
	70		TOTAL DISTRIB PLANT	$ 1,429,900,376		$ 38,351,636
	71		GENERAL PLANT			
	72	389.1	LAND	$ 95,891	0.00%	$ -
		389.2	LAND RIGHTS	$ 104,242	0.00%	$ -
	73	390	STRUCTS & IMPRVMNTS	$ 15,437,742	1.73%	$ 267,073
	74	391.1	OFC FURN & EQP	$ 7,043,410	7.71%	$ 543,048
		391.2	CMPTERS AND PERIPHRAL EQP	$ 43,762,460	32.79%	$ 14,349,711
	75	392.1	AUTOS	$ 42,796	0.00%	$ -
		392.2	TRAILERS	$ 2,078,047	0.00%	$ -
		392.3	TRUCKS	$ 2,961,028	0.00%	$ -
		392.4	TRUCKS	$ 1,074,986	0.00%	$ -
	76	393	STORES EQUIPMENT	$ 1,974,880	7.45%	$ 147,126
	77	394	TOOLS, SHP, & GRG EQP	$ 20,719,098	6.25%	$ 1,294,944
	78	395	LAB EQUIPMENT	$ 18,291,037	9.36%	$ 1,712,041
	79	396	PWR OPERATED EQP	$ 22,708,765	0.00%	$ -
	80	397	COMMUNICATION EQUIP	$ 21,044,944	11.56%	$ 2,432,796
	81	398	MISC EQP	$ 2,077,428	6.41%	$ 133,163
	82		TOTAL GENERAL PLANT	$ 159,416,752		$ 20,880,100
	83					
	84	SUSP	SUSPENSE	$ -	0.00%	$ -
	85		DEFERRED-SUGAR CREEK		0.00%	$ -
	86		ELECTRIC PLANT IN SERVICE	$ 5,308,264,363		$ 157,766,398

ELECTRIC DEPRECIATION	$ 157,766,398
COMMON DEPRECIATION	$ 21,048,318
SUGAR CREEK DEPRECIATION	$ 11,578,252
TOTAL PLANT IN SERVICE DEPRECIATION	$ 190,392,968

* Rates changed from filed Case-In-Chief

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JOINT
EXHIBIT No. Exhibit B
9-12-11
DATE
REPORTER
RL

Northern Indiana Public Service Company
Statement of Operating Income
Actual, Pro Forma, Proposed and Settlement
For the Twelve Month Period Ending June 30, 2010

Line No.	Description	Actual	Pro Forma Adjustments Increases (Decreases)	Ref.	Pro Forma Results Based on Current Rates	Pro Forma Adjustments Increases (Decreases)	Ref	Filed Pro Forma Results Based on Proposed Rates	Settlement Adjustments	Settlement Pro Forma Results Based on Proposed Rates
	A	B	C	D	E	F	G	H	I	J
1	Operating Revenue									
2	Revenue	$ 1,290,077,061			$ 1,394,146,282	75,740,199	PF-1	$ 1,469,886,481	$ (68,886,481)	$ 1,401,000,000 (1)
3	Abnormal Weather		15,693,447	REV - 1						
4	Interdepartmental Sales - LNG Liquefaction		293,468	REV - 2						
5	Aggregate Planning Resource Credits		(937,500)	REV - 3						
6	Special Contracts		32,792,263	REV - 4						
7	EDR Rates		1,116,049	REV - 5						
8	Interest - FAC71 Legal Fees		(30,111)	REV - 6						
9	MISO Transmission Revenue		(3,205,777)	REV - 7						
10	Expiration of Customer Credit		58,789,378	REV - 8						
11	FAC 80 S1 Settlement Adjustment		(800,000)	REV - 9						
12	Fuel Costs Recovery - Lighting Tariffs		499,511	REV - 10						
13	Capacity Sales Adjustment		(141,607)	REV - 11						
14	Total Operating Revenue	$ 1,290,077,061	$ 104,069,221		$ 1,394,146,282	$ 75,740,199		$ 1,469,886,481	$ (68,886,481)	$ 1,401,000,000
15	Fuel and Purchased Power	$ 473,066,869			$ 474,458,056			$ 474,458,056	$ -	$ 474,458,056
16	Abnormal Weather		4,661,013	FP - 1						
17	Interdepartmental Sales - LNG Liquefaction - Fuel		194,246	FP - 2						
18	Aggregate Planning Resource Credits - Costs		(337,500)	FP - 3						
19	Gas & Diesel - Gen Stations		18,335	FP - 4						
20	Capacity Purchases		(3,375,000)	FP - 5						
21	Accounting Accrual Adjustment		230,093	FP - 6						
22	Total Fuel and Purchased Power	$ 473,066,869	$ 1,391,187		$ 474,458,056	$ -		$ 474,458,056	$ -	$ 474,458,056
23	Gross Margin	$ 817,010,192	$ 102,678,034		$ 919,688,226	$ 75,740,199		$ 995,428,425	$ (68,886,481)	$ 926,541,944
24	Operations and Maintenance Expenses	$ 382,060,512			$ 389,318,655	203,687	PF - 2	$ 389,522,342	$ (185,256)	$ 363,237,597
25	Line Locates		(259,417)	OM - 1						
26	Vegetation Management		3,437,162	OM - 2						
27	Gas & Diesel		10,385	OM - 3						
28	Wage Increase		5,465,525	OM - 4						
28a	Pension								(17,151,702)	
29	Incentive Adjustment		1,283,166	OM - 5						
30	Environmental Expense Adjustment		(668,000)	OM - 6						
31	Labor Adjustment		(3,249,936)	OM - 7						
32	BU Signing Bonus		(22,400)	OM - 8						
33	Corp Services - NCSC		(1,248,857)	OM - 9						
34	Gary Business Office Relocation		(125,640)	OM - 10						
35	Lobbying / EEI		(78,183)	OM - 11						
36	Institutional Goodwill Advertising		(12,449)	OM - 12						
37	Advertising		(1,854,005)	OM - 13						
38	Selected Payments		(45,055)	OM - 14						
39	Excess / Obsolete Material		(2,023,458)	OM - 15						
40	Insurance Reimbursement		445,774	OM - 16						
41	MISO Administrative Fee		5,326,931	OM - 17						
42	Gypsum Expense Adjustment		876,600	OM - 18						
43	Settlement Adjustment								(8,947,788)	
44	Total Operations and Maintenance	$ 382,060,512	$ 7,258,143		$ 389,318,655	$ 203,687		$ 389,522,342	$ (26,284,745)	$ 363,237,597

(1) NIPSCO's base rates will be designed to produce $1.355 billion, which is the revenue requirement of $1.401 billion less approximately $42m of other revenue and $4m emission allowance credit as ordered in Cause 43526.

Northern Indiana Public Service Company
Statement of Operating Income
Actual, Pro Forma, Proposed and Settlement
For the Twelve Month Period Ending June 30, 2010

Line No.	Description	Actual	Pro Forma Adjustments Increases (Decreases)	Ref.	Pro Forma Results Based on Current Rates	Pro Forma Adjustments Increases (Decreases)	Ref	Filed Pro Forma Results Based on Proposed Rates	Settlement Adjustments	Settlement Pro Forma Results Based on Proposed Rates
	A	B	C	D	E	F	G	H	I	J
45	Depreciation Expense	$ 193,896,526			$ 195,298,357			$ 195,298,357	$ (4,905,389)	$ 190,392,968
46	Depreciation Expense - New Rates		1,401,831	DA - 1						
47	Total Depreciation Expense	$ 193,896,526	$ 1,401,831		$ 195,298,357	$ -		$ 195,298,357	$ (4,905,389)	$ 190,392,968
48	Amortization Expense	$ 12,850,263			$ 37,688,102			$ 37,688,102		$ 36,500,530
49	Amortization Expense (Reg Assets) - MISO (4 yr)		3,876,018	DA - 2						
50	Amortization Expense (Reg Assets) - MISO Cause No. 43526 (4 yr)		5,732,141	DA - 2A						
51	Amortization Expense (Reg Assets) - Rate Case (3 yr)		770,162	DA - 3						
52	Amortization Expense (Reg Assets) - Rate Case Cause No. 43526 (5 yr)		1,187,572	DA - 3A					(1,187,572)	
53	Amortization Expense - Deferred Sugar Creek Depreciation (5 yr)		2,029,113	DA - 4						
54	Amortization Expense - Deferred Sugar Creek Depreciation Cause No. 43526 (5 yr)		1,459,652	DA - 4A						
55	Amortization Expense - Deferred Sugar Carrying Charges (5 yr)		6,287,705	DA - 5						
56	Amortization Expense - Deferred Sugar Carrying Charges Cause No. 43526 (5 yr)		4,541,120	DA - 5A						
57	Amortization Expense - RM Schahfer Unit 17 Deferred Depreciation		(193,544)	DA - 6						
58	Amortization Expense - RM Schahfer Unit 17 Carrying Charges		(852,000)	DA - 7						
59	Total Amortization Expense	$ 12,850,263	$ 24,837,839		$ 37,688,102	$ -		$ 37,688,102	$ (1,187,572)	$ 36,500,530
60	Taxes									
61	Taxes Other than Income	$ 54,999,209			$ 60,334,582			$ 60,334,582		$ 57,719,217
62	Real Estate Taxes		3,084,954	OTX - 1					(2,615,365)	
63	Payroll Tax		455,104	OTX - 2						
64	Indiana Utility Receipts Tax		1,602,321	OTX - 3		1,060,363	PF - 3	1,060,363	(964,411)	95,952
65	Public Utility Fee		192,994	OTX - 4		90,055	PF - 4	90,055	(81,906)	8,149
66	Total Taxes Other Than Income	$ 54,999,209	$ 5,335,373		$ 60,334,582	$ 1,150,418		$ 61,485,000	$ (3,661,682)	$ 57,823,318
67	Income Taxes									
68	Federal and State Taxes	$ 57,557,401	$ 15,318,907	ITX - 1	$ 72,876,308	$ 30,203,550	PF - 5	$ 103,079,858	$ (13,364,569)	$ 89,715,289
69	Total Taxes	$ 112,556,610	$ 20,654,280		$ 133,210,890	$ 31,353,967		$ 164,564,857	$ (17,026,250)	$ 147,538,607
70	Total Operating Expenses	$ 701,363,911	$ 54,152,093		$ 755,516,004	$ 31,557,654		$ 787,073,659	$ (49,403,957)	$ 737,669,702
71	Required Net Operating Income	$ 115,646,281	$ 48,525,941		$ 164,172,222	$ 44,182,544		$ 208,354,766	$ (19,482,524)	$ 188,872,242

[1] NIPSCO's base rates will be designed to produce $1,355 billion, which is the revenue requirement of $1,401 billion less approximately $42m of other revenue and $4m emission allowance credit as ordered in Cause 43526.

Allocation of Base Rate Revenue Requirement

	Base Rate Revenue Requirement		% of Total
Rate 611	$	377,800,682	27.882%
Rate 612	$	5,160,037	0.381%
Rate 613	$	1,225,658	0.090%
Rate 617	$	79,874	0.006%
Rate 620	$	629,024	0.046%
Rate 621	$	179,174,263	13.223%
Rate 622	$	1,198,071	0.088%
Rate 623	$	156,979,496	11.585%
Rate 624	$	192,453,641	14.203%
Rate 625	$	3,187,081	0.235%
Rate 626	$	59,229,608	4.371%
Rate 632	$	140,914,919	10.400%
Rate 633	$	121,519,285	8.968%
Rate 634	$	94,742,567	6.992%
Rate 641	$	2,356,647	0.174%
Rate 642	$	83,773	0.006%
Rate 644	$	1,862,949	0.137%
Rate 650 -Street Lighting	$	8,864,654	0.654%
Rate 655 - Traffic Lighting	$	917,431	0.068%
Rate 660 - Dusk-to-Dawn	$	2,221,152	0.164%
Interdepartmental	$	4,399,188	0.325%
Total	$	1,355,000,000	100.000%

Generally applicable:

- Rates and charges revised consistent with agreed base rate revenue of $1,355 million and class allocations contained within Settlement Agreement
- Subject to agreeable language for all tariffs, general terms and conditions of service, and standard contract applicable to certain industrial tariffs.

Rates 611 (Residential), 612 (Single Family Residential – Heat Pump) and 613 (Multiple Family Residential Housing – Heat Pump):

- $11 customer charge
- Single energy block (i.e., no declining blocks)
- Standardize spaceheating kilowatt breakpoint with spaceheating/heat pump rates at 700 kWh

Discontinuation of Spaceheating/Heat Pump Rates:

- Gas heating incentive ($25) below-the-line
- NIPSCO agrees to file for the Commission's consideration within two years of an Order in this Cause a rate design analysis for its residential space heating rates that provides revenue neutral transition plans to discontinue discounts from standard rates for space heating customers and any required alterations to the rates of the standard customers on these rate schedules.

Rates 620 (Commercial and General Service – Heat Pump) and 622 (Commercial Spaceheating):

- $20 customer charge

Rate 621 (General Service – Small):

- $20 customer charge, with the exception of a $34 customer charge for three-phase service customers
- Single energy block (i.e., no declining block)

Rate 625 (Metal Melting Service)

- Current tariff structure (peak and off-peak hours) is generally retained.

Rate 632 (Industrial Power Service):

- Grandfather test year customers and/or load as migrated
- Increase minimum threshold to 15 MW
- Single demand charge rate

- Three inclining energy blocks

Rate 633 (High Load Factor Industrial Power Service):

- Grandfather test year customers and/or load as migrated
- Three declining energy blocks
- No embedded energy/hours in the demand component

Rate 634 (Industrial Power Service for Air Separation & Hydrogen Production Market Customers)

- New rate schedule available to air separation and hydrogen production market customers with contract minimum of 150 MW, including aggregation of multiple delivery points to facilitate interruption of load
- Customer required to contract for at least 40 percent (40%) as interruptible in accordance with Option D under Rider 675
- Demand Charge assessed on Contract Demand
- Three block Energy Charges based upon kilowatt hours used under Contract Demand, between Contract Demand and 225,000 KW and kilowatt hours used over 225,000 KW.
- Determination of Contract Demand based upon average of on-peak demands and subject to 12.5% bandwidth

Rider 670 (Adjustment of Charges for Cost of Fuel Rider)

- Modified to include recovery of 25% of costs associated with credits paid for interruptible load

Rider 674 (Adjustment of Charges for Resource Adequacy)

- Modified to include recovery of 75% of costs associated with credits paid for interruptible load

Rider 675 (Interruptible Industrial Service Rider)

- *See* Joint Exhibit F

Rider 676 (Back-up, Maintenance and Temporary Industrial Service Rider)

- *See* Joint Exhibit G

Rider 677 (Economic Development Rider)

- Modified to include new eligibility threshold requirement of a minimum of 10 full-time equivalent jobs created per project

Demand Allocators

Table 1

		Demand Allocators - Production Rate Base	% of Total
Rate 611	$	874,364,266	27.03%
Rate 612	$	11,568,405	0.36%
Rate 613	$	2,491,423	0.08%
Rate 617	$	567,352	0.02%
Rate 620	$	2,460,930	0.08%
Rate 621	$	321,313,655	9.93%
Rate 622	$	3,167,196	0.10%
Rate 623	$	352,718,755	10.90%
Rate 624	$	381,527,692	11.80%
Rate 625	$	10,357,175	0.32%
Rate 626	$	149,042,043	4.61%
Rate 632	$	486,895,971	15.05%
Rate 633	$	359,680,007	11.12%
Rate 634	$	258,398,965	7.99%
Rate 641	$	4,083,935	0.13%
Rate 642	$	40,353	0.00%
Rate 644	$	3,382,779	0.10%
Rate 650 - Street Lighting	$	3,183,659	0.10%
Rate 655 - Traffic Lighting	$	1,792,941	0.06%
Rate 660 - Dusk-to-Dawn	$	873,080	0.03%
Interdepartmental	$	6,685,997	0.21%
Total	$	3,234,596,580	100.0%

RIDER 675
INTERRUPTIBLE INDUSTRIAL SERVICE RIDER

TO WHOM AVAILABLE

Available to Customers taking service under either Rate 632, Rate 633 or Rate 634 whose facilities are located adjacent to existing electric facilities having capacity sufficient to meet the Customer's requirements, subject to the conditions set forth in this Rider and the Company Rules. The total capacity to be made available under this Rider is limited to 500 MW and the total sum of demand credits available under this Rider shall not exceed $38,000,000 in any calendar year. If initial requests for capacity exceed the 500 MW cap, the priority of allocation will be first to existing interruptible customers and then the remaining capacity will be allocated on a pro rata share.

Customers shall contract for and specify an Interruptible Contract Demand of 1,000 kW or greater under this Rider. The Company shall not be obligated to supply interruptible capacity in excess of the Interruptible Contract Demand specified in the contract. Interruptible Contract Demand is the demand (kW) that the Customer intends to make available for Interruptions and/or Curtailments from one or more of Customer's premises taking service under Rate 632, Rate 633 or Rate 634. Customers electing service under this Rider shall specify a Firm Contract Demand that the Customer intends to exclude from Interruptions and Curtailments. The Firm Contract Demand amount shall be specified in the customer's agreement. The Interruptible Contract Demand shall not exceed the Rate 632, Rate 633 or Rate 634 Demand.

For Options A, B, and C, if Customer elects to provide Interruptible Contract Demand from more than one premise, Customer shall indicate the Interruptible Contract Demand and Firm Contract Demand that applies in aggregate to its premises as well as by each premise or facility. In these instances, Company shall have the right to call Customer for the Interruptible Contract Demand quantity in aggregate from Customer, and Customer shall indicate from which facility or premise it will utilize to satisfy the obligations under this Rider.

Customers electing this rider shall be required to have the ability of Curtailment or Interruption at the stated notice by the Company and the provisions of service under this Rider to Customers shall also meet the applicable Load Modifying Resource requirements pursuant to Midwest ISO Tariff Module E or any successor. Customers electing this Rider shall provide information necessary to satisfy these requirements, including information demonstrating to Company's satisfaction that the Customer has the ability to reduce load to the level of curtailability and/or interruptibility for which they contract.

CHARACTER OF SERVICE

There are four options of interruptible service. The Customer shall contract for the interruptible option which shall remain in effect for the duration of the contract.

The Company shall dispatch customers for the Curtailments or Interruptions at its own discretion in accordance within the limitations specified under this Rider and the Company's General Rules and Regulations Applicable to Electric Service.

RIDER 675
INTERRUPTIBLE INDUSTRIAL SERVICE RIDER

Option A – Curtailments only

Curtailments shall be limited to the following:

1. No more than one (1) per day;
2. No more than four (4) hours per day;
3. No more than five (5) days during the summer (May – September).

The Company shall provide at least four (4) hours advanced notice before a Curtailment. This service will be billed as second through the meter.

Option B – Curtailment and Limited Interruptions

1. Customer will be subject to the Curtailments defined in Option A plus
2. Interruptions shall be limited as follows:
   a. No more than one (1) per day,
   b. No more than ten (10) consecutive hours,
   c. No more than two (2) consecutive days,
   d. No more than three (3) in any seven (7) days of the week, and
   e. No more than 100 hours per rolling 365 days.

The Company shall provide at least four (4) hours advanced notice before an Interruption or Curtailment. Adjustments to the requested Interruptible demand may be increased with a minimum of four (4) hour notice during the Interruption. Once notice is given to a Customer, an Interruption of a minimum of at least four (4) consecutive hours in length will be deemed to have occurred for purposes of the above limits even if the Company subsequently provides a notice of cancellation of such Interruption. This service will be billed as second through the meter.

Option C – Curtailment and Interruptions

1. Customer will be subject to Curtailments unlimited as to quantity and duration plus
2. Interruptions shall be limited as follows:
   a. No more than one (1) per day,
   b. No more than 12 consecutive hours,
   c. No more than two (2) consecutive days,
   d. No more than three (3) in any seven (7) days of the week, and
   e. No more than 100 hours per rolling 365 days.

RIDER 675
INTERRUPTIBLE INDUSTRIAL SERVICE RIDER

The Company shall provide at least one (1) hour advanced notice before an Interruption or Curtailment. Adjustments to the requested Interruptible demand may be increased with a minimum of one (1) hour notice during the Interruption. Once notice is given to a Customer, an Interruption of a minimum of at least four (4) consecutive hours in length will be deemed to have occurred for purposes of the above limits even if the Company subsequently provides a notice of cancellation of such Interruption. This service will be billed as second through the meter.

Option D – Curtailment and Short notice Interruptions

1. Customer will be subject to Curtailments unlimited as to quantity and duration plus
2. Interruptions shall be limited as follows:
   a. No more than one (1) per day,
   b. No more than 12 consecutive hours,
   c. No more than three (3) consecutive days during weekdays (Monday – Friday), and
   d. No more than 200 hours per rolling 365 days.

The Company shall provide at least ten (10) minute advanced notice before an Interruption or Curtailment. Adjustments to the requested Interruptible demand may be increased with a minimum of ten (10) minutes notice during the Interruption. Once notice is given to a Customer, an Interruption of a minimum of at least four (4) consecutive hours in length will be deemed to have occurred for purposes of the above limits even if the Company subsequently provides a notice of cancellation of such Interruption. This service will be billed as first through the meter.

INTERRUPTIONS

Company may call an Interruption when the applicable real-time LMPs for the Company's load zone are reasonably forecasted by the Company to be in excess of the Company's current Commission-approved purchased power benchmark that is utilized to develop the Company's fuel cost charge under Rider 670. Company shall provide a good faith estimate of the duration of an Interruption based upon the information available to Company.

Customers may elect to buy-through an Interruption subject to the Energy rate provided in this Rider.

RATE

Demand Credit

Option A

On the effective date of this Rider:	$1.00 per kilowatt per Interruptible Billing Demand per month will be applied to the Rate 632, Rate 633 or Rate 634 bill.

RIDER 675
INTERRUPTIBLE INDUSTRIAL SERVICE RIDER

Starting every subsequent February 1: The annual market price per kilowatt per month for capacity deliverable to the NIPSCO load zone as determined by the Company through an average of quotes taken from candidate bilateral counterparties in the wholesale market (or reasonably similar information available to Company) during the preceding January.

Option B

\$6.00 per kilowatt per Interruptible Billing Demand per month will be applied to the Rate 632, Rate 633 or Rate 634 bill.

Option C

\$8.00 per kilowatt per Interruptible Billing Demand per month will be applied to the Rate 632, Rate 633 or Rate 634 bill.

Option D

\$9.00 per kilowatt per Interruptible Billing Demand per month will be applied to the Rate 632, Rate 633 or Rate 634 bill.

Energy

During Interruptions, all kilowatt hours used above the Interruptible Contract Demand plus the firm Contract Demand less the amount requested for Interruption shall be subject to an energy charge equal to the Real-Time LMP for the Company's load zone plus a non-fuel energy charge as follows:

Rate 632:	\$0.005702 per kilowatt hour
Rate 633:	\$0.005108 per kilowatt hour
Rate 634:	\$0.003009 per kilowatt hour.

Prior to 9 AM CST day-ahead, a Customer may elect in writing to Company to pay the Day-Ahead LMP for the Company's load zone in place of the Company's Real-Time LMP for the Company's load zone for any energy taken by the Customer pursuant to this Rider during any Interruptions that occur for that operating day.

DETERMINATION OF INTERRUPTIBLE BILLING DEMAND

Interruptible billing demand shall be calculated as follows:

RIDER 675
INTERRUPTIBLE INDUSTRIAL SERVICE RIDER

Options A, B & C:

The lessor of:

(1) the Interruptible Contract Demand, or
(2) Billing demand of the either Rate 632, Rate 633 or Rate 634 less firm Contract Demand.

Option D:

The lessor of:

(1) the Interruptible Contract Demand, or
(2) Billing demand of either Rate 632, Rate 633 or Rate 634.

The customer's monthly Rate 632, Rate 633 or Rate 634 Billing Demand shall be calculated in accordance with Rate 632, Rate 633 or Rate 634.

The interruptible demand credit will not apply to Back-up, Maintenance or Temporary Service demands taken under Rider 676.

CUSTOMER'S FAILURE TO COMPLY WITH REQUESTED INTERRUPTIONS OR CURTAILMENT

A Customer is deemed to have failed to comply with a Curtailment or Interruption when the Customer's current integrated Demand, as measured by the meters installed by the Company, has not decreased to a level equal to or less than its Firm Contract Demand plus its Interruptible Contract Demand less the amount requested within the applicable notification period of the option for Interruptions and/or Curtailments.

If a Customer fails to comply with a Curtailment, the Customer shall be immediately disqualified and removed from service under this Rider and shall not be eligible for this Rider for a period of three (3) years. In addition, a Customer failing to comply with a Curtailment shall be subject to the above energy charge during a Curtailment and, the Customer shall be liable for any charges and/or penalties from any outside agency(ies) or duly applicable organization including Midwest ISO, FERC and Reliability*First* Corporation for failure to comply with a Curtailment. Penalties and charges may be, but are not limited to, penalties associated with disqualification as a Load Modifying Resource.

For Interruptions, the only consequence of such compliance failure will be that the Customer will be deemed to have elected to buy-through its Interruption pursuant to the Energy charge under this Rider to the extent the Customer failed to interrupt its demand.

RIDER 675
INTERRUPTIBLE INDUSTRIAL SERVICE RIDER

GENERAL TERMS AND CONDITIONS OF SERVICE - CONTRACT

Any Customer requesting service under this rate shall enter into a written contract for an initial period of:

Option A:	Not less than one (1) year.
Option B:	Not less than three (3) years.
Option C:	Not less than seven (7) years.
Option D:	Not less than 10 years.

Customers electing Options B, C or D under this Rider shall have the option once each year by February 15 to modify its Interruptible Contract Demand by plus or minus 10 percent (10%), subject to the overall availability under this Rider. A Customer electing to modify its Interruptible Contract Demand shall also agree to make corresponding changes to its Firm Contract Demand and other provisions in its contract impacted by such modification.

To the extent Customers electing Options B, C or D experience a material change in plant operations and provide Company at least 60 days' advance notice, the contract under this Rider, including the Interruptible Contract Demand and Firm Contract Demand, may be modified to accommodate such change upon mutual agreement of Customer and Company.

In such contract, it shall also be proper to include such provisions, if any, as may be agreed upon between the Company and the Customer with respect to special terms and conditions under which service is to be furnished hereunder, including but not limited to, amount of Contract Demand, voltage to be supplied, and facilities to be provided by each party in accordance with the Company Rules.

Notwithstanding the above, contracts under this Rider shall expire upon the date of Company's implementation of new electric basic rates and charges resulting from a general rate proceeding.

RULES AND REGULATIONS

Service hereunder shall be subject to the Company Rules and IURC Rules.

RIDER 676
BACK-UP, MAINTENANCE AND TEMPORARY INDUSTRIAL SERVICE RIDER

TO WHOM AVAILABLE

Available to Customers taking service under either Rate 632 or Rate 633 who desire to take service from the Company on a temporary basis, including for back-up or maintenance purposes, subject to Curtailments. Back-up, Maintenance, and Temporary Services under this Rider shall be subject to Curtailments when curtailment of the Company's interruptible service customers under Rider 675 is insufficient.

CHARACTER OF SERVICE

Subject to the provisions applicable to Back-up, Maintenance or Temporary Service under this Rider, Customer shall request in writing, which can be via electronic mail, an amount of capacity and the duration said capacity shall be needed. The Company shall by written notice, which can be via electronic mail, confirm the amount of capacity it is willing to accept as load on its system and the duration said capacity shall be available to the Customer.

Back-up Service
Subject to the requirements of Back-up Service in this Rider, a Customer with verified internal electric generation fueled with energy sources such as, but not limited to, process off-gas or waste heat, natural gas, oil, propane, coal and coal by-products and that is capable of meeting the efficiency standards established for a cogeneration facility by the Federal Energy Regulatory Commission under 16 U. S. C. 824a-3, in effect November 9, 1978 ("Cogeneration Systems") may request (including on a pre-qualifying basis) Back-up Service that may only be available for up to 45 calendar days per Cogeneration System per 12 rolling months. Eligibility for Back-Up Service requires a contract between the Customer and Company that shall include information on the Cogeneration System(s). Customer shall provide initial notice of request of Back-up Service within 60 minutes of event, including (i) information reasonably verifying such event, (ii) expected outage schedule, and (iii) daily notice to Company thereafter during and throughout the conclusion of an event.

Maintenance Service
Subject to the requirements of Maintenance Service in this Rider, the amount confirmed by Company shall be deemed firm load, subject to Curtailments.

Temporary Service
Subject to the requirements of Temporary Service in this Rider, the amount confirmed by Company shall be deemed firm load, subject to Curtailments. To the extent Customer requests Temporary Service and Company denies such a request under this Rider, Customer may elect to buy-through subject to the Demand and Energy Charges during Buy-through provided in this Rider. Customer may not elect to buy-through under this Rider if Company has initiated a Curtailment(s) on its system. The Company has the right to deny a request if Day Ahead LMPs exceed the Company's current Commission-approved purchased power benchmark that is utilized to develop the Company's fuel cost charge under Rider 670.

RIDER 676
BACK-UP, MAINTENANCE AND TEMPORARY INDUSTRIAL SERVICE RIDER

RATE

Back-up Service

For Back-up service, the following charges shall apply:

Demand Charge:

The demand charge shall be the applicable Rate 632 or Rate 633 demand charge, divided by the number of calendar days within the applicable calendar month, per kilowatt per day.

Energy Charge

All kilowatt hours used for Back-up service shall be subject to an energy charge equal to Real-Time LMP plus a non-fuel energy charge of $0.0035 per kilowatt hour.

All energy for Back-up Service shall be billed on an hourly basis at the lower of: (i) 100% load factor for the confirmed Back-up Service capacity or (ii) the total energy consumed by the Customer under this Rider and either Rate 632 or Rate 633, as applicable, during the period in which Back-up Service capacity was taken by the Customer.

Maintenance Service

For Customers (i) requesting service in writing at least 30 days in advance of the need for maintenance service, (ii) requesting service for days not including June, July, August and September, and (iii) maintaining such requested daily schedule without material change, the following charges shall apply for up to a maximum of 60 calendar days in any 12 month rolling period:

Demand Charge

For Customers requesting service for January, May and/or December, the Demand Charge shall be $0.44 per kilowatt per day.

For Customers requesting service for February, March, April, October and/or November, the Demand Charge shall be $0.25 per kilowatt per day.

Energy Charge

The energy charge for all kilowatt hours shall be the applicable energy charge in Rate 632 or Rate 633.

To the extent Customer seeks to recall the amount of Maintenance Service confirmed by Company, Customer shall provide at least 48 hours prior notice. In such instance, Company shall confirm to Customer the amount recalled within 24 hours of notice of recall and such recalled amounts shall not contribute towards the maximum days permitted under this Rider.

RIDER 676
BACK-UP, MAINTENANCE AND TEMPORARY INDUSTRIAL SERVICE RIDER

Temporary Service
For Temporary service, the following charges shall apply:

Demand Charge (except as defined for buy-through described below)
\$0.58 per kilowatt per day for the first 30 calendar days of temporary demand take in any 12 month rolling period;
\$0.87 per kilowatt per day for the second 30 calendar days of temporary demand take in any 12 month rolling period;
\$1.16 per kilowatt per day for the third 30 calendar days of temporary demand take in any 12 month rolling period; and
\$2.32 per kilowatt per day for all calendar days in excess of 90 of temporary demand take in any 12 month rolling period.

Energy Charge (except as defined for buy-through described below)
The energy charge for all kilowatt hours shall be the applicable energy charge in Rate 632 or Rate 633.

All energy for Temporary Service shall be billed on an hourly basis at the lower of: (i) 100% load factor for the confirmed Temporary Service capacity or (ii) the total energy consumed by the Customer under this Rider and either Rate 632 or Rate 633, as applicable, during the period in which Temporary Service capacity was taken by the Customer.

Buy-Through Temporary Service

Demand Charge (during buy-through)
There shall be no demand charge for Temporary Service during a buy-through event.

Energy Charges (during buy-through)
All kilowatt hours used for Temporary service during buy-through shall be subject to an energy charge equal to Real-Time LMP plus a non-fuel energy charge of \$0.0035 per kilowatt hour.

All energy for Temporary Service shall be billed on an hourly basis at the lower of: (i) 100% load factor for the requested Temporary Service capacity or (ii) the total energy consumed by the Customer under this Rider and either Rate 632 or Rate 633, as applicable, during the period in which Temporary Service capacity was taken with buy-through by the Customer.

Subject to the amount requested by Customer, during a buy-through event there is no cap on kWh's imported or duration of buy-through for that applicable operating day. Buy-through days do not count toward the number of days of Temporary Service during any rolling 12 month period.

This Rider is subject to the Midwest ISO charges or credits associated with the service.

RIDER 676
BACK-UP, MAINTENANCE AND TEMPORARY INDUSTRIAL SERVICE RIDER

DETERMINATION OF BILLING DEMAND

The billing demand for the day for Maintenance Service shall be the greater of (i) the granted Maintenance Service capacity times 80% or (ii) the actual amount of Maintenance Service taken by Customer above the billing demand under Rate 632 or Rate 633. To the extent Company has confirmed a recall of Maintenance Service under the provisions of this Rider, Customer shall not be charged for the amount recalled.

The billing demand for the day for Back-up and Temporary Service shall be the confirmed amount of Back-up and Temporary Service.

RULES AND REGULATIONS

Service hereunder shall be subject to the Company Rules and IURC Rules.

Rule 10.2 Non-Residential Customers

The Company shall determine the creditworthiness of an Applicant or Customer in an equitable non-discriminatory manner.

A Customer shall be deemed creditworthy if it has no delinquent bills to the Company for electric service within the last twenty-four (24) months and, within the last two (2) years has not: (a) had service disconnected for nonpayment or (b) filed a voluntary petition, has a pending petition, or has an involuntary petition filed against it, under any bankruptcy or insolvency law. For purposes of this determination a contested bill shall not be considered delinquent.

In determining the creditworthiness of Applicants, the Company shall consider the size of the credit exposure and the availability of objective and verifiable information about the Applicant. The Company may consider the Applicant's payment history from other utilities and verifiable conditions such as, but not limited to: Applicant 's independently audited annual and quarterly financial statements, including an analysis of its leverage, liquidity, profitability and cash flows; and credit rating agency information.

The Company may require from any uncreditworthy Applicant or Customer, as a guarantee against the non-payment of bills, a deposit payable in cash or by letter of credit in an amount equal to the Customer's two (2) highest months usage based upon the most recent twelve (12) months historical usage or two months of projected usage for an Applicant. For Customers with multiple accounts, each account will be treated individually for purposes of this Rule.

If the Company requires a deposit as a condition of providing service, upon request of the Customer or Applicant, the Company must: (a) provide written explanation of the facts upon which the utility based its decision; and (b) provide the Applicant or Customer with an opportunity to rebut the facts and show other facts demonstrating its creditworthiness.

Upon the request of the Customer, but no more than once every twenty four (24) consecutive months, the Company will conduct a reevaluation of Customer's creditworthiness with repayment of the security deposit or portion thereof as appropriate, within 60 days and with written notice identifying the basis for any continued deposit.

In the case of a cash deposit as a guarantee against the payment of bills, simple interest thereon at the rate established by the Indiana Utility Regulatory Commission shall be paid by the Company for the time such deposit is held by the Company. Upon discontinuance of service, the amount of the final bill will be deducted from the sum of the deposit and interest due, and the balance, if any, shall be remitted to the depositor.

ORIGINAL

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY FOR THE ISSUANCE OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE CONSTRUCTION OF CLEAN COAL TECHNOLOGY ("THE PROJECTS"), INCLUDING ONGOING REVIEW OF THE PROJECTS, PURSUANT TO IND. CODE CH. 8-1-8.7; FOR A FINDING THAT (1) SUCH PROPERTY CONSTITUTES QUALIFIED POLLUTION CONTROL PROPERTY AND IS ELIGIBLE FOR THE RATEMAKING TREATMENT PURSUANT TO IND. CODE § 8-1-2-6.8, (2) SUCH PROPERTY CONSTITUTES CLEAN COAL AND ENERGY PROJECTS AND IS ELIGIBLE FOR THE RATEMAKING AND FINANCIAL TREATMENT PURSUANT TO IND. CODE CH. 8-1-8.8, (3) THE PROJECTS ARE DEEMED TO BE UNDER CONSTRUCTION UNTIL SUCH TIME AS THE COMMISSION DETERMINES THAT THE PROJECTS ARE USED AND USEFUL, AND (4) THAT THE PROJECTS ARE ELIGIBLE FOR THE DEPRECIATION TREATMENT SET FORTH IN IND. CODE §8-1-2-6.7; FOR AUTHORIZATION TO (1) DEFER AND AMORTIZE ASSOCIATED DEPRECIATION AND OPERATION AND MAINTENANCE EXPENSES, (2) DEFER PRECONSTRUCTION COSTS INCURRED PRIOR TO THE ISSUANCE OF A FINAL ORDER HEREIN, (3) ACCRUE ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION RELATED TO QUALIFIED POLLUTION CONTROL PROPERTY PRIOR TO CONSTRUCTION WORK IN PROGRESS RATEMAKING TREATMENT, (4) PERFORM CERTAIN DISPATCH OF PETITIONER'S GENERATION UNITS, AND (5) RECOVER THE COST OF CERTAIN RENEWABLE ENERGY CREDITS; AND FOR APPROVAL OF A REVISED COST ESTIMATE FOR CONSTRUCTION PROJECTS PREVIOUSLY APPROVED IN CAUSE NO. 43913.	CAUSE NO. 44012 APPROVED: SEP 05 2012

PHASE III ORDER OF THE COMMISSION

Presiding Officers:
David E. Ziegner, Commissioner
Aaron A. Schmoll, Senior Administrative Law Judge

On March 22, 2011, Northern Indiana Public Service Company ("Petitioner" or "NIPSCO") filed its Verified Petition in this Cause. On April 26, 2011, after conferring with the

Indiana Office of Utility Consumer Counselor ("OUCC"), NIPSCO filed a Motion for Procedural Schedule, which set forth an agreed procedural schedule. Said Motion was granted by Docket Entry dated May 11, 2011. On April 28, 2011, the NIPSCO Industrial Group ("Industrial Group") filed its petition to intervene, which was subsequently granted. On May 2, 2011, NIPSCO prefiled direct testimony of its witnesses Kelly R. Carmichael, Kurt W. Sangster, Ronald G. Plantz and Curt A. Westerhausen.

On June 27, 2011, the OUCC filed a Motion for Extension of Time and Request for Attorneys' Conference requesting an extension of time for it and the Industrial Group to file their cases-in-chief. The OUCC's request for an Attorneys' Conference was granted by Docket Entry dated June 29, 2011. In lieu of an Attorneys' Conference, the parties met informally on June 29, 2011 to discuss the procedural issues in this Cause. On July 1, 2011, NIPSCO, the OUCC and Industrial Group filed a Joint Motion to Modify Procedural Schedule ("Joint Motion") requesting the procedural schedule be modified and converted to a bifurcated proceeding to allow the Commission to address NIPSCO's request for relief in two phases and for certain accounting treatment for the projects to be addressed in the second phase of this Cause. An Attorneys' Conference was convened on July 13, 2011 to discuss the parties' request at which time the parties' request for a modified procedural schedule and bifurcated proceeding was granted. Phase I addressed and resolved the following three projects ("Phase I Projects"):

(1) Schahfer Unit 14 Flue Gas Desulphurization ("FGD") Facility Addition;
(2) Schahfer Unit 14/15 FGD Common; and
(3) Schahfer Unit 15 FGD Additions.

At that time, Phase II would have addressed and resolved the remaining projects that were the subject of NIPSCO's petition in this Cause:

(1) Michigan City Unit 12 FGD Facility Addition;
(2) Bailly Unit 7 Selective Catalytic Reduction ("SCR") Duct Burners;
(3) Bailly Unit 8 SCR Duct Burners;
(4) Michigan City Unit 12 SCR Duct Burners;
(5) Schahfer Unit 14 SCR Duct Burners;
(6) Schahfer Unit 15 Selective Non-Catalytic Reduction ("SNCR") Installation; and
(7) Continuous Particulate Monitors ("CPM") Addition for Units 7, 8, 12, 14, 15, 17 and 18.[1]

In accordance with the revised procedural schedule, NIPSCO prefiled Phase I supplemental direct testimony and exhibits of its witnesses Michael Hooper and Ronald G. Plantz on July 21, 2011. On July 26, 2011, NIPSCO filed a Notice of Order Approving Consent Decree. The OUCC prefiled Phase I direct testimony of its witnesses Ray L. Snyder, Cynthia M. Armstrong and Wes R. Blakley and the Industrial Group prefiled Phase I direct testimony of its witness James R. Dauphinais. NIPSCO prefiled the Phase I rebuttal testimony of Messrs. Carmichael, Hooper and Plantz. The Commission issued a Docket Entry on August 26, 2011, directing Petitioner to respond to questions, to which Petitioner responded on August 30, 2011.

[1] In this Order, we will also refer to Schahfer Units 14 and 15 as "Units 14 and 15," Bailly Units 7 and 8 as "Units 7 and 8," and Michigan City Unit 12 as "Unit 12."

Pursuant to notice given as provided by law, proof of which was incorporated into the record, an evidentiary hearing to address Phase I was held in this matter on August 31, 2011, at 9:30 a.m., in Room 222, PNC Center, 101 West Washington Street, Indianapolis, Indiana. At the hearing, the Phase I prefiled evidence of NIPSCO, OUCC and Industrial Group were admitted into the record without objection. No members of the general public appeared or participated at the hearing. We subsequently issued an Order in this Cause with respect to the Phase I Projects on December 28, 2011.

While Phase I remained pending and awaiting Order, we proceeded with Phase II. On August 18, 2011, NIPSCO and the OUCC submitted an agreed procedural schedule for Phase II.[2] In accordance with that agreement, NIPSCO prefiled Phase II supplemental direct testimony and exhibits on August 18, 2011. On August 19, 2011, NIPSCO filed a motion for administrative notice of NIPSCO's redacted version of its Integrated Resource Plan ("IRP") admitted into the record in Cause No. 43643. On October 20, 2011, the OUCC prefiled its Phase II direct testimony and exhibits. On October 21, 2011, the Industrial Group also prefiled its Phase II direct testimony. The testimony of the OUCC and the Industrial Group generally supported or did not oppose NIPSCO's requested relief with respect to all Phase II Projects other than the FGD, CPM and SCR Duct Burners for Michigan City Unit 12. For the projects associated with Unit 12, both the OUCC and Industrial Group opposed the relief at that time on the basis that more analysis was needed of available alternatives to the proposed environmental controls. On November 9, 2011, NIPSCO, OUCC and Industrial Group filed a Stipulation and Settlement Agreement ("Settlement") and Motion for Modification of Procedural Schedule. In their Settlement and Motion, the joint movants requested the Commission to approve a settlement with respect to all projects that had been deferred to Phase II other than the projects associated with Michigan City Unit 12 (the "Stipulated Phase II Projects") and moved the Commission for entry of an agreed procedural schedule for a new Phase III to be established in this Cause with respect to the Michigan City Unit 12 projects. The Stipulated Phase II Projects included the following five projects:

(1) Unit 7 SCR Duct Burners;
(2) Unit 8 SCR Duct Burners;
(3) Unit 14 SCR Duct Burners;
(4) Unit 15 SNCR Installation; and
(5) CPM Addition for Units 7, 8, 14, 15, 17 and 18.

Phase III would then address and resolve the following Michigan City projects ("Phase III Projects"):

(1) Unit 12 FGD Facility Addition;
(2) Unit 12 SCR Duct Burners;[3]
(3) CPM Addition for Unit 12.

[2] Although this proceeding has been trifurcated into three phases, all phases have proceeded in the same docket and under the same cause number. As a result, all evidence of record submitted during any of the evidentiary hearings conducted for any phase of this proceeding is part of one evidentiary record for the entire cause.

[3] The Phase III Projects now include Water Side Bypass technology instead of Duct Burners, as explained herein.

More specifically, Phase III would focus on an analysis of potential available alternatives to refitting Unit 12 with the Phase III Projects. This issue bears on whether the public convenience and necessity supports the issuance of the requested certificate, which is one of the statutory elements we are to consider.

Pursuant to notice given as provided by law, proof of which was incorporated into the record, an evidentiary hearing to address Phase II was held in this matter on December 14, 2011, at 9:30 a.m., local time, in Room 222 of the PNC Center, 101 West Washington Street, Indianapolis, Indiana. At the hearing, the Phase II prefiled evidence of NIPSCO, OUCC and Industrial Group, including the Settlement, and Petitioner's responses to the Commission's December 6, 2011 Docket Entry questions, were admitted into the record without objection. On the record at the evidentiary hearing, the Commission approved the request of the parties to establish Phase III and read into the record an agreed procedural schedule to govern Phase III. No members of the general public appeared or participated at the hearing. We subsequently issued an Order in this Cause with respect to Phase II on February 15, 2012.

While Phase II remained pending and awaiting Order, the parties proceeded with Phase III to address the remaining Phase III Projects. On February 16, 2012, NIPSCO prefiled Phase III supplemental direct testimony and exhibits. Petitions to Intervene were filed by New Covert Generating Company, LLC ("NCG"), BP Products North America Inc. ("BP") and St. Joseph Energy Center, LLP ("SJEC"), which were granted by Docket Entries dated February 28, 2012 (NCG and BP) and April 9, 2012 (SJEC).[4] On April 12, 2012, the OUCC, Industrial Group and SJEC each filed Phase III testimony and exhibits constituting their respective cases-in-chief, and on April 27, 2012, NIPSCO filed its Phase III rebuttal testimony and exhibits. Thereafter on May 7, 2012, NIPSCO responded to questions propounded by the Commission via Docket Entry.

Pursuant to notice given as provided by law, proof of which was incorporated into the record, an evidentiary hearing to address Phase III was held in this matter on May 10, 2012, at 9:30 a.m., local time, in Room 222 of the PNC Center, 101 West Washington Street, Indianapolis, Indiana. At the hearing, the Phase III prefiled evidence of NIPSCO, OUCC, and Industrial Group, SJEC, and Petitioner's responses to the Commission's Docket Entry questions were admitted into the record without objection. In addition, Petitioner's Exhibit CX-III-1 and Public's Exhibit CX-1-III were admitted into the record without objection. No members of the general public appeared or participated at the hearing.

Having considered the evidence and being duly advised, the Commission now finds:

1. <u>Notice and Jurisdiction</u>. Due, legal and timely notice of the hearing in this Cause was given as required by law. Petitioner is a "public utility" as defined in Ind. Code § 8-1-2-1(a) and Ind. Code § 8-1-8.7-2, a "utility" as that term is used in Ind. Code § 8-1-2-6.8(a) and 170 I.A.C. 4-6-1(n), and an "eligible business" as that term is defined in Ind. Code § 8-1-8.8-6. Petitioner is subject to the jurisdiction of this Commission, in the manner and to the extent provided by Indiana law. Accordingly, the Commission has jurisdiction over Petitioner and the subject matter of this proceeding.

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[4] BP was originally a member of the Industrial Group but withdrew from the Industrial Group shortly before filing its own petition to intervene.

2. **Petitioner's Characteristics and Generating System.** Petitioner is a public utility organized and existing under the laws of the State of Indiana and having its principal office at 801 East 86th Avenue, Merrillville, Indiana. Petitioner provides 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 electric power to the public. The NIPSCO generating facilities have a total capacity of 3,322 megawatts ("MWs") and consist of numerous separate generation sites, including Petitioner's R.M. Schahfer Generating Station ("Schahfer"), Michigan City Generating Station ("Michigan City"), Bailly Generating Station ("Bailly"), Sugar Creek Generating Station ("Sugar Creek") and two (2) hydroelectric generating sites near Monticello, Indiana. Of the total capacity, 77.5% is from coal-fired units, 22.2% is from natural gas-fired units and 0.3% is from hydroelectric units.

Michigan City is located on the shore of Lake Michigan in Michigan City, Indiana. Michigan City formerly had the two oldest generating units on NIPSCO's system, Units 2 and 3, which have been removed from service. Michigan City's newer Unit 12 remains in service and currently burns low sulfur coal.

3. **Background and Requested Relief.** On January 13, 2011, an agreement was entered into between the United States Environmental Protection Agency ("EPA"), Department of Justice, Indiana Department of Environmental Management and NIPSCO to settle a NIPSCO EPA New Source Review Notice of Violation that had been lodged with the United States District Court for the Northern District of Indiana Hammond Division ("Northern District") (the "Consent Decree"). The Consent Decree was placed on public notice in the Federal Register on January 20, 2011. On July 22, 2011, the Northern District issued an Order in Case No. 2:11-CV-16 JVB approving the Consent Decree. The Consent Decree requires that NIPSCO operate all existing pollution control equipment and install additional pollution control equipment.

In addition to the Consent Decree, NIPSCO will soon need to comply with new federal and state environmental regulations, including EPA's final Cross State Air Pollution Rule ("CSAPR") released on July 6, 2011[5] and the final National Emission Standards for Hazardous Air Pollutants for Coal- and Oil-fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial- Commercial-Institutional Steam Generating Units-Final Rule ("Utility MACT") released on February 16, 2012 that will require NIPSCO to further reduce its nitrogen oxides ("NOx"), sulfur dioxides ("SO_2") and other hazardous air pollutant emissions ("HAPs") over the next several years (collectively, the "EPA Regulations"). As NIPSCO explained in its Responses to our December 6, 2011 Docket Entry and during the stakeholder process, additional air emissions controls beyond what is being installed in Phase I and Phase II and sought in Phase III of this proceeding will likely be needed to fully comply with the Utility MACT rule. NIPSCO is currently evaluating what additional controls may be necessary to comply with the February 16, 2012 final rule. However, installation of the Unit 12 FGD provides significant

[5] On August 21, 2012, the D.C. Circuit Court of Appeals vacated CSAPR. *EME Homer Generation, L.P. v. EPA*, 11-1302 et al. (Aug. 21, 2012). However, the D.C. Circuit required EPA to continue to administer the Clean Air Interstate Rule ("CAIR"). *Id.* at 60.

progress towards meeting the Utility MACT requirements at the Michigan City Generating Station.

To meet the requirements of the Consent Decree and make progress towards meeting the EPA Regulations, NIPSCO has developed a Multi-Pollutant Compliance Plan set forth in Petitioner's Exhibit No. KWS-1. In order to control emissions of SO_2, the Multi-Pollutant Compliance Plan includes the installation of FGD systems on Michigan City Unit 12, among others. With respect to emissions of NOx, the Multi-Pollutant Compliance Plan originally included the installation of SCR Duct Burners on (among others) Michigan City Unit 12. NIPSCO has recently (during Phase III) revised its plan to install Duct Burners and now proposes to install in their place Water Side Bypass technology ("WSB") for Unit 12. Further study has revealed that the WSB can effectively remove NOx to acceptable levels at a substantial cost savings. The Multi-Pollutant Compliance Plan also includes the installation of CPMs on Unit 12 (among others). By its Petition in this Cause, NIPSCO requests, among other things, a certificate of public convenience and necessity ("CPCN") for each of the projects included in its Multi-Pollutant Compliance Plan pursuant to Ind. Code Ch. 8-1-8.7 and approval for these projects pursuant to Ind. Code Ch. 8-1-8.8. Our earlier two Orders in this Cause have granted NIPSCO's requested relief as to all projects except the Phase III Projects, which are the Michigan City Unit 12 FGD, WSB and CPM.

By its Petition, Petitioner requests the following relief with respect to the Phase III Projects:

(a) the issuance of a CPCN to Petitioner for the Phase III Projects to reduce SO_2 and NOx emissions pursuant to Ind. Code § 8-1-8.7-1 *et seq.*;

(b) approval of cost estimates for the Phase III Projects;

(c) ongoing review of the Phase III Projects pursuant to Ind. Code § 8-1-8.7-7;

(d) a finding that the Phase III Projects constitute "qualified pollution control property" and are eligible for the ratemaking treatment described in Ind. Code § 8-1-2-6.8;

(e) a finding that the Phase III Projects constitute "clean energy projects" under Ind. Code Ch. 8-1-8.8, and a finding that the Phase III Projects are reasonable and necessary and therefore eligible for the timely recovery of costs and expenses incurred during construction and operation as set forth in Ind. Code Ch. 8-1-8.8-11(a)(1);

(f) authorization to utilize for the Phase III projects construction work in progress ("CWIP") ratemaking treatment for clean coal technology ("CCT"), qualified pollution control property ("QPCP") and clean energy projects consistent with and through Petitioner's currently-effective Environmental Cost Recovery Mechanism ("ECRM");

(g) authorization to recover operating and maintenance ("O&M") expenses relating to the Phase III Projects, including depreciation expense, for CCT, QPCP and clean energy projects consistent with and through Petitioner's currently-effective Environmental Expense Recovery Mechanism ("EERM");

(h) authorization to defer for recovery through rates pre-construction costs incurred prior to approval of a Final Order in this proceeding to the extent that such costs are reasonable and prudent and consistent with the scope of the Phase III Projects as further described in Petitioner's evidence through Petitioner's currently-effective ECRM and EERM;

(i) a finding that the Phase III Projects are eligible for the depreciation treatment set forth in Ind. Code § 8-1-2-6.7;

(j) authorization to accrue allowance for funds used during construction ("AFUDC") related to QPCP prior to CWIP ratemaking treatment or their reflection of such costs in NIPSCO's electric rates for the Phase III projects;

(k) a finding that the Phase III Projects are deemed to be under construction until such time the Commission determines that the Phase III Projects are used and useful in a proceeding that involves the establishment of new electric basic rates and charges for Petitioner;

(l) authorization to perform dispatch of its generation units in a manner necessary to comply with the requirements of the Consent Decree and declaring such procedures to be in compliance with current and future dispatch parameters relating to the recovery of fuel costs; and

(m) such other relief afforded and authorized by the applicable statutes, regulations, orders and tariffs.

4. <u>Evidence Presented in Phases I and II related to Phase III Projects</u>. In Phases I and II, Petitioner, the OUCC and Industrial Group filed direct testimony and exhibits and supplemental direct testimony and exhibits that addressed their respective positions on the Multi-Pollutant Compliance Plan, including the Phase III Projects. Evidence submitted in earlier phases and relating to the Phase III Projects is summarized as follows:

A. <u>Petitioner's Direct Testimony</u>.

i. <u>Direct Testimony of Kelly R. Carmichael</u>. NIPSCO Witness Carmichael described and summarized the settlement of the EPA New Source Review Notice of Violation which ultimately resulted in the Consent Decree. He addressed the status of existing and upcoming federal and state environmental requirements that will require NIPSCO to make capital investments to reduce air emissions. He further discussed various federal and state environmental air regulations impacting the continued operation of NIPSCO's electric generating units including the EPA Clean Air Interstate Rule ("CAIR"), the proposed EPA Clean Air Transport Rule ("CATR")[6] and the Utility MACT standards. He explained that these regulations

[6] On July 7, 2011, EPA approved CSAPR, which took the place of CATR.

will require NIPSCO to further reduce its NOx, SO_2, and other HAPs over the next several years. His testimony focused on the installation of pollution control systems to meet the requirements of both the Consent Decree and EPA's regulatory requirements.

NIPSCO Witness Sangster testified in support of NIPSCO's request for a CPCN for the Phase III Projects. He sponsored NIPSCO's Multi-Pollutant Compliance Plan (Petitioner's Exhibit No. KWS-1), described the pollution control technologies included in the Plan, and also provided the estimated project costs and O&M estimates.

NIPSCO Witness Westerhausen testified concerning NIPSCO's requested ratemaking treatment. He explained that NIPSCO proposes to utilize CWIP ratemaking treatment for CCT, QPCP and clean energy projects consistent with and through its existing ECRM. He testified that NIPSCO further proposes to recover O&M expenses related to the Phase III Projects, including depreciation expense for CCT, QPCP and clean energy projects consistent with and through NIPSCO's EERM. He further explained that NIPSCO proposes to recover through the ECRM the return on capital expenditures for each approved project beginning six months after the construction start date of the project and that NIPSCO proposes to recover through the EERM O&M and depreciation expenses associated with each approved project beginning when it is placed in service. Mr. Westerhausen also testified regarding NIPSCO's request to submit semi-annual progress reports as part of its ECRM filings.

NIPSCO Witness Plantz testified in support of NIPSCO's requested accounting treatment for investments in all Multi-Pollutant Compliance Plan QPCP and CCT projects.

NIPSCO Witness Hooper provided supplemental direct testimony to provide additional support for NIPSCO's request for a CPCN. He provided additional information relating to NIPSCO's enhanced project team, general project planning and cost estimation principles, and the relationship between Indiana's CPCN statutes and project planning and cost estimation. He further explained NIPSCO's processes to control costs and meet the project deadlines, and NIPSCO's recommendation for an ongoing reporting requirement to provide transparent information regarding the costs and progress of the Phase III Projects to stakeholders.

ii. Phase II Supplemental Direct Testimony of Kelly R. Carmichael. NIPSCO Witness Carmichael provided a status update regarding the Consent Decree. He explained that on July 22, 2011, the Northern District issued an Order in Case No. 2:11-CV-16 JVB approving the Consent Decree, which was not changed from the Consent Decree lodged on January 13, 2011. Mr. Carmichael provided a summary of the CSAPR. He also provided an update regarding the Michigan City Unit 12 FGD schedule.

Mr. Carmichael testified that NIPSCO believed the final Utility MACT rule would require NIPSCO to accelerate the schedule for the Unit 12 FGD and that engineering would need to begin as early as the first quarter of 2012 to meet the projected Utility MACT timeline. He explained that the Unit 12 FGD construction schedule initially proposed by NIPSCO was based on the Consent Decree deadline. He explained why Utility MACT would require the FGD to be in service prior to the Consent Decree and that if NIPSCO does not install control technology on Unit 12, it would exceed the expected emissions limits for SO_2, mercury, and particulate matter. Regarding the potential alternatives to installing FGD technology on Unit 12, Mr. Carmichael testified that Unit 12 could be shutdown either permanently or for a period of time between the Utility MACT standards deadline and the Consent Decree deadline. He testified that temporary shutdown raises a host of potential problems including an EPA requirement to go through New Source Review prior to restart, loss of CSAPR allocations for Michigan City Unit 12, third-party legal challenges to prevent restart and exposure to the purchase power market as a result of Michigan City Unit 12 not being available.

iii. <u>Phase II Supplemental Direct Testimony of Guy H. Ausmus.</u> NIPSCO Witness Ausmus testified in support of his analysis that ultimately concluded the retrofit of Michigan City Unit 12 was the preferred option. He first testified that, although Unit 12 has the capability of operating on natural gas, switching Unit 12 from burning coal to burning natural gas was not an option because NIPSCO would not be permitted to switch to gas for fuel and later switch back to coal. He sponsored a spreadsheet analysis which compared the projected net present value of the Unit 12 retrofit to the construction of a hypothetical 500 MW combined cycle combust turbine unit ("CCGT").

B. <u>OUCC's Phase II Direct Testimony.</u>

i. <u>Phase II Direct Testimony of Ray L. Snyder.</u> In Phase II, Mr. Snyder testified about the overall costs of the proposed Phase III Projects and the prospects for cost increases. He expressed concerns about Mr. Ausmus' evaluation of alternatives and ultimately recommended that the Commission deny the requested relief with respect to all Michigan City Unit 12 projects.

ii. <u>Phase II Direct Testimony of Brendon Baatz.</u> Mr. Baatz testified in Phase II that the OUCC did not support the Unit 12 projects. He was concerned that there are additional environmental projects associated with the Unit 12 projects that are not included in the Petition in this Cause but which could have a material impact on the total cost of environmental compliance. He was also concerned that NIPSCO had not modeled the impacts of potential carbon legislation.

iii. <u>Industrial Group Phase II Direct Testimony of James R. Dauphinais.</u> Mr. Dauphinais testified in Phase II that the Commission should deny the requested relief for the Unit 12 Projects at that time. He recommended that NIPSCO further refine its cost estimates for the FGD and CCGT alternatives and also explore potential market options. Further, he had specific objections to the assumptions in Mr. Ausmus' economic analysis and requested that it be refined to bring it within reasonable bounds. He recognized that there are looming compliance deadlines upcoming, but he nevertheless urged that these steps be taken to strengthen the analysis before he could support the issuance of a CPCN.

5. **Phase III Evidence.** The evidence in Phase III was devoted to exploring the potential alternatives to refitting Unit 12 with the Phase III Projects, which bears upon whether the public convenience and necessity is supported by our issuance of the requested certificate for the Phase III Projects.

A. **Petitioner's Phase III Supplemental Direct Testimony.**

i. **Phase III Supplemental Direct Testimony of Cecelia Largura.** Cecelia Largura, Director of Strategic Execution for NIPSCO testified regarding the additional analysis conducted in Phase III and described how NIPSCO worked with the OUCC and the Industrial Group (collectively the "Stakeholders")[7] to develop a process for evaluating options for addressing the environmental needs associated with Michigan City Unit 12. She explained that after the OUCC and Industrial Group raised concerns in Phase II about the Michigan City Unit 12 retrofit, NIPSCO had undertaken additional analysis to respond to those concerns. On November 23, 2011, NIPSCO met with the Stakeholders to solicit their input on NIPSCO's 2011 Base/Intermediate Request for Proposals (the "RFP"). The RFP was then issued in December 2011. Thereafter, the Stakeholders met frequently and repeatedly to discuss an analytical approach to identify the best possible alternative. Ms. Largura testified that her purpose in relaying what transpired at these meetings was not intended to suggest that the Stakeholders had agreed to anything about the process or the results but rather to communicate the degree to which NIPSCO involved the Stakeholders to solicit their input. She testified that the study horizon used was NIPSCO's 2011 IRP (2012-2032), but at the suggestion of one of the Stakeholders, it was adjusted to include the cost of capital decisions beyond the study horizon known as "End Effects.". As a result of the Stakeholder process, NIPSCO analyzed alternatives including RFP responses, and both large and small self-build CCGT generator projects. Ms. Largura concluded that the economic analysis produced as a result of the Stakeholder process indicated to NIPSCO that refitting Michigan City Unit 12 with the Phase III Projects is the reasonable cost option with the least amount of risk.

ii. **Phase III Supplemental Direct Testimony of Charles F. Adkins.** Charles F. Adkins, Vice President in the consulting practice of Ventyx, LLC, was retained to conduct the RFP, to solicit market options to replace Michigan City Unit 12, and to examine thoroughly the retire and refit options for Michigan City Unit 12. He explained the analysis NIPSCO used to evaluate its various options to retire or refit Michigan City Unit 12 and ultimately concluded that refitting Michigan City Unit 12 with the Phase III Projects is the preferred option to meet the future energy needs in a cost effective manner.

Mr. Adkins testified that the viable options are (1) refit Michigan City Unit 12 with the Phase III Projects, (2) retire Michigan City Unit 12 and replace with Midwest Independent System Operator ("MISO") market capacity and energy, (3) retire Michigan City Unit 12 and replace with a large CCGT, (4) retire Michigan City Unit 12 and replace with a small CCGT and (5) retire Michigan City Unit 12 and replace with a market option solicited through the RFP. Mr. Adkins' analysis included recovery of capital investment, modification of fixed and variable

[7] BP, NCG and SJEC were bidders in response to the request for proposals that grew out of the Stakeholder process. BP withdrew from the Industrial Group and filed its independent petition to intervene, and SJEC and NCG both intervened following the receipt of responses to the RFP. As a result, these "bidder" intervening parties did not participate in the Stakeholder process.

operating and maintenance expenses, projects to comply with anticipated mercury and coal combustion residuals ("CCR") rules and Clean Water Act regulations. His analysis did not include the cost of duct burners (now WSB) or costs of depreciation and demolition of Michigan City Unit 12. Mr. Adkins explained that these costs were not included because the duct burners or WSB would be needed under both a refit or a retire option and under both refit and retire the cost of remaining depreciation and demolition of Unit 12 were assumed to be recovered. He testified that NIPSCO used the 2011 IRP as a starting point of its analysis and the associated sensitivities for base, high market, low market, and no carbon. He noted that all Stakeholders had different views but agreed that the 2011 IRP was a good starting point for analysis. Rather than running through a large number of potential alternate future and energy commodity markets, Mr. Adkins instead identified the break points that switch the decision from refit to retire. The same break point analysis could then be used with other key decision drivers such as carbon regulation, project over-run costs, etc. NIPSCO utilized the planning model Strategist® and then provided the Stakeholders spreadsheets on which they could perform individual analysis or extract data.

Mr. Adkins then explained how the results of the RFP were included in the analysis. First, Ventyx ensured that proposals were complete, received on time, and signed by a duly authorized officer or agent. Next, they underwent a threshold screen where various proposals failed for not offering a term with a sufficient minimum length or for offering a term starting sooner than requested. Obvious errors were corrected, and a debt equivalence adjustment was added. The debt equivalence adjustment represents the imputed revenue requirement for any additional common equity required to maintain NIPSCO's current debt/equity ratio given recently published guidelines that long term purchased power agreements are being viewed in the marketplace as additional debt. Finally a congestion adder was made to reflect the impact of MISO congestion and marginal losses between the location/delivery point and the NIPSCO load hub.

After these various adjustments were made, each proposal was individually compared to the market. Proposals that were "out of the money" were eliminated. Mr. Adkins used the 2011 IRP as the starting point for the definition of the "market." The refit of Michigan City Unit 12 option was then compared to replacing the capacity with the market, to replacing with a large CCGT, to replacing with a small CCGT, to replacing with each of the remaining ten RFP proposals that remained after the economic screening, and finally to replacing with combinations of the four smaller RFP proposals. Based upon the net present value of the revenue requirements and under the base case, high market and no carbon sensitivities, refitting Michigan City Unit 12 was the most cost effective option. Using the breakpoint analysis, Mr. Adkins then determined the breakpoints for the price of natural gas and escalation where the decision to refit Michigan City Unit 12 would flip. There was no breakpoint where a replacement with a large CCGT became preferred. It was only under the low market scenario with implementation of carbon constraints in 2020 that replacement with a small CCGT or any of the RFP responses became preferred.

Finally, Mr. Adkins conducted a risk assessment which was not utilized in his financial model. This was intended to show the levels of risk inherent with each of the options. He concluded that refitting Michigan City Unit 12 is the option with the lowest cost and the least amount of risk.

B. <u>OUCC's Phase III Direct Testimony</u>.

i. <u>Phase III Direct Testimony of Ray L. Snyder</u>. Mr. Snyder provided the OUCC's analysis of NIPSCO's request and commented on the RFP bids. He noted that the accuracy range of NIPSCO's cost estimates is now +/- 40%. He testified that while this was less than order of magnitude estimates described in earlier phases of this proceeding (+100%/-50%), it still provided a significant range of potential costs. With potential future projects for mercury, Clean Water Act, and CCRs and the range of cost of projects for which a CPCN is sought, Mr. Snyder computed NIPSCO's estimate to be $325 million and the high estimate to be $503 million. As a result, he testified that the OUCC believes alternatives should be considered. Mr. Snyder noted that there were two RFP bids meriting comment. One was a nuclear facility located out of state which was rejected because it proposed a start date before the term set forth in the RFP. The second was a bid submitted by Intervenor SJEC.

Mr. Snyder was appreciative of the collaborative Stakeholder process. He testified that the weekly meetings and exchange of information, ideas and concerns was extremely beneficial in identifying points of agreement or disagreement and working toward resolution where there were conflicting ideas or opinions.

ii. <u>Phase III Direct Testimony of Brendon J. Baatz</u>. Mr. Baatz testified that in Phase III NIPSCO has expanded the scope of analysis regarding options to retrofit of Michigan City Unit 12 to include further market options identified through the RFP, including purchase power agreements, market purchases of existing resources; and refined estimates for newly constructed combined cycle gas turbine units. He testified NIPSCO accommodated the Stakeholders using Microsoft Excel Worksheets to relay information computed through Strategist®, with each spreadsheet representing a different "case." Mr. Baatz also testified that the use of a more complex system wide modeling tool such as Strategist® is more suitable for the analysis necessary for this cause. NIPSCO included in its economic analysis the cost of the FGD system, compliance with an anticipated CCR rule based upon the assumption the final rule will regulate coal ash as a non-hazardous substance, compliance with an anticipated Clean Water Act cooling water intake rule, and an activated carbon injection system.

Mr. Baatz noted that the Stakeholders did not agree on all input assumptions utilized in the process. There was disagreement over forecasted prices of natural gas, inclusion or not of duct burners in the modeling, the adjustment for debt equivalence, and the modeling of carbon impacts. Mr. Baatz testified that NIPSCO's base case assumption from its 2011 IRP for forecasted prices of natural gas was above other market forecasts that he has reviewed and the low case assumptions were at or above other market forecasts. However, Mr. Baatz stated that although the stakeholders did not agree on all commodity assumptions, this concern would be alleviated after NIPSCO completed sensitivity analyses for all scenarios.

Mr. Baatz testified that he was not convinced that NIPSCO would have to install duct burners (or WSB) on Michigan City Unit 12 if it were to be retired. He noted that the 30-day rolling average for NOx might be very close to the levels required by the Consent Decree without the duct burners. He also questioned whether the debt equivalence adjustment was appropriate but noted that the debt equivalence adjustment did not have an impact on the final results.

Mr. Baatz testified that of all the RFP responses, only two were economically competitive with the Phase III Projects. One was the nuclear option, which was rejected because it included a start-date which was earlier than the required start-date in the RFP. The second was SJEC's proposal, which would produce a lower net present value of revenue requirements under the 2011 IRP low case for natural gas price forecast. He was also critical of Mr. Adkins' analysis of risk. In Mr. Baatz's opinion, the construction and technology risk of SJEC should have been scored with less risk than the Michigan City Unit 12 retrofit. He also pointed out the risks and uncertainties associated with fuel price volatility and future fossil fuel regulations which would impact all alternatives in this cause. On cross-examination, however, Mr. Baatz testified that with the commitments now being made by NIPSCO concerning future cost increases (described later), he agrees that his concerns about risk associated with the Phase III Projects have been addressed.

C. Industrial Group's Phase III Direct Testimony of James R. Dauphinais. Mr. Dauphinais testified that the Industrial Group no longer opposes NIPSCO's proposed Michigan City Unit 12 Phase III Projects. He did recommend that the Commission condition any approval of the requested CPCN on NIPSCO adhering to the same Stakeholder reporting and meeting requirements that were imposed in the Phase I Order in this Cause. He testified that he agreed with the improvements in NIPSCO's economic analysis for the proposed Unit 12 investments, including further refinement of cost estimates, further exploration of market options, and a reasonable effort to update and revise its economic analysis. He was still concerned that NIPSCO's natural gas price assumptions were too high but that use of Strategist® allowed the Industrial Group to see results using more "reasonable" natural gas price assumptions in addition to results using NIPSCO's higher natural gas prices from its IRP Base Case commodity price assumptions. He testified that consensus on gas price assumptions is not needed because even under lower natural gas prices, none of the alternatives to the Michigan City Unit 12 refit were ultimately more attractive on a forecast basis than moving forward with the Unit 12 investments.

Mr. Dauphinais was also concerned with NIPSCO's updated and revised analysis because it focused on comparing the 20-year net present value benefit (with post-2032 end effects added) of the alternatives to the proposed Michigan City Unit 12 investments without consideration of how much time must pass before a cumulative net present value benefit from any of the other options would be realized. According to Mr. Dauphinais, the longer the period that must pass before a net present value benefit would be achieved, the greater the risk that the forecasted net present value benefit will not be realized. Mr. Dauphinais conducted a year-by-year analysis with a lower natural gas price assumption and which compared the Michigan City Unit 12 refit to (1) the best RFP bid received that was comparable in size to Michigan City Unit 12, (2) construction by NIPSCO of a CCGT comparable in size to Michigan City Unit 12, and (3) the best RFP bid received in response that was significantly larger in size than Michigan City Unit 12. He also stress-tested various assumptions by allowing up to a 40% cost overrun on the Michigan City Unit 12 FGD system and other changes in assumptions. He ultimately concluded (1) that the best RFP bid comparable in size to the Michigan City Unit 12 under reasonable assumptions did not produce a forecasted net present value benefit until after 2032; (2) that the best RFP bid comparable in size to Michigan City Unit 12 under very favorable assumptions to the RFP bid did not produce a benefit until 2025 – nine years after the assumed retirement of Unit 12; (3) that construction of a CCGT comparable in size to Michigan City Unit 12 under reasonable assumptions would not produce a benefit until after 2032 (2026 under very favorable assumptions to the CCGT), (4) and the best RFP bid significantly larger in size did not produce a net present value benefit until 2022.

In Mr. Dauphinais' opinion, neither a PPA comparable in size to Michigan City Unit 12 nor NIPSCO construction of a new CCGT comparable in size to Michigan City Unit 12 are attractive alternatives to the Michigan City Unit 12 refit. The closest was the RFP bid significantly larger in size, which would require NIPSCO to take a significant long position in the market by purchasing an extra 160 MW capacity it does not presently need. In Mr. Dauphinais' opinion, taking a significant long position in the market is not consistent with providing reliable electric service to retail customers at the lowest reasonable cost, and it would have ratepayers taking on undue risk by effectively having them speculate in the wholesale power market.

D. <u>SJEC's Phase III Direct Testimony of William Ladd</u>. William Ladd testified on behalf of SJEC, one of the bidders in response to the RFP. He testified that SJEC's bid relates to a project which is in an advanced stage of redevelopment and has completed major milestones. He testified that NIPSCO had not properly evaluated the RFP responses because of flaws in assumptions and omission of significant factors. The first flaw in assumptions that he identified was the natural gas price forecast used, which Mr. Ladd testified were "dramatically inflated." The second flaw that he identified was the use of the currently estimated cost of the environmental projects because Mr. Ladd believed that these costs could double. The third flaw he identified was the exclusion of SCR duct burners and CPMs from the analysis. In his view the analysis should have been conducted on the assumption that Michigan City Unit 12 would be retired at the end of 2013 and using market purchases as a bridge until SJEC's project is completed in 2016. The last flaw that he identified was the failure to consider multiple variables moving at once.

The omissions that Mr. Ladd identified were (1) a risk that the Michigan City Unit 12 projects would not be able to comply with Utility MACT, (2) that no value was assigned to fuel diversity and (3) that no value was assigned to the construction of new power plants in Indiana. In Mr. Ladd's opinion, NIPSCO should be required to address these deficiencies and the request only approved based upon a comprehensive analysis with accurate inputs.

E. <u>Petitioner's Phase III Rebuttal Testimony</u>.

i. <u>Phase III Rebuttal Testimony of Frank A. Shambo</u>. Frank A. Shambo, Vice President of Regulatory and Legislative Affairs for NIPSCO, testified in rebuttal that the Unit 12 projects present the solution with the reasonable balance of cost, risk and policy. He testified that NIPSCO's natural gas assumptions and sensitivities are reasonable and the forecasts are based upon reasonable sources and conditions, especially given that natural gas prices are volatile and difficult to predict. Further he testified that low natural gas prices would only impact the analysis when combined with carbon constraints and that it is unlikely that natural gas prices would remain low when carbon constraints take effect. He testified that the decision for the Commission is a binary one – whether NIPSCO should be granted a CPCN for the Phase III Projects. The decision is not whether NIPSCO should enter a power purchase agreement with any of the RFP bidders. He further testified that the decision on Unit 12 cannot be delayed beyond the third quarter of 2012 without risking the loss of Unit 12. He testified that if NIPSCO stops running Unit 12 on coal it is unlikely it will ever be able to return operations to coal regardless of the relative cost of coal or gas in the future. There is no time or need for further study because it would provide too much risk to the ability to maintain Unit 12 as an alternative.

With respect to natural gas price forecasts, Mr. Shambo testified that NIPSCO utilized a range of forecasts including base, low and high and that there is no need for further analysis. Further he testified that NIPSCO's commodity assumptions were not derived specifically for this case but were instead rooted in disciplined planning that is connected to the IRP process. Those commodity forecasts were prepared by PIRA Energy Group, again unconnected to this case.

Mr. Shambo testified that the economic analysis demonstrates that only one of the PPA options would ultimately provide ratepayer benefits and only then in later years out in time and only under the assumptions of both a carbon constraint and a low natural gas price forecast. He testified that natural gas price forecasts are inherently unreliable and a review of past forecasts shows that forecasting is fraught with uncertainty and frequently wrong in terms of direction and by large amounts. He testified that the industry has consistently erred in estimating future gas prices or production capabilities. In the face of this uncertainty, it is critical to focus on what we do know with some level of certainty. Mr. Shambo testified that even under the low gas cost assumption he agreed with the Industrial Group that it is more appropriate for customers to receive benefits in the early years rather than receive benefits many more years into the future.

Mr. Shambo also described uncertainties related to a purchased power agreement ("PPA") that is from an asset yet to be constructed. While some of the risks can be mitigated, it does not change the fact that construction could be halted and leave NIPSCO searching for adequate supplies to meet the needs of its customers.

With respect to diversification, Mr. Shambo testified that this issue must be considered as a part of the IRP and not in isolation. This is further complicated by the fact that the decision not to refit Unit 12 would be irreversible. Further, he noted that diversification must be considered from a viewpoint of customers, many of whom already use abundant natural gas for heat or manufacturing processes. Increasing the amount of generation that uses natural gas as a feed stock would actually intensify the customer's price exposure to natural gas.

Mr. Shambo testified that the decision to shut down Unit 12 would be irreversible and that efficient coal-fired generating stations are irreplaceable. Unit 12 is one of the largest and most efficient units within NIPSCO's fleet. If the public convenience and necessity does not support installation of FGD technology, it begs the question of what other unscrubbed coal units must also be eliminated in the state and region. Mr. Shambo testified that this would indicate that support for one of the critical resources the state has to offer – coal – is in jeopardy. In his view, the FGD technology would avoid a "preemptive surrender" of one of NIPSCO's efficient coal-fired facilities within Indiana while achieving emission reduction standards that benefit the region. He stated this is consistent with the state's strategic energy plan, also known as Hoosier Home Grown Energy.

Finally, Mr. Shambo agreed with Witness Dauphinais' recommendation that the requested CPCN should be conditioned upon NIPSCO's adherence to the same Stakeholder reporting and meeting requirements that were imposed in the Commission's Phase I Order. He also indicated that NIPSCO agreed to use a 20-year depreciation rate with two caveats: (1) if the project is later deemed inoperable due to future environmental regulations or requirements, NIPSCO should preserve the right to request a shorter amortization schedule and (2) that if a CPCN is not granted for the FGD, NIPSCO would need a shorter depreciation schedule for the WSB and CPMs to accommodate the fact that these projects would not be in service for 20 years. Without the FGD, NIPSCO would be willing to accept a 3-year amortization period for the remaining projects. In conclusion, Mr. Shambo testified that the Unit 12 projects are the most appropriate path forward and are in the public interest. He opined that NIPSCO's requested relief should be granted.

ii. <u>Phase III Rebuttal Testimony of Michael Hooper</u>. Mr. Hooper testified on rebuttal that it is important a decision be made on the Unit 12 projects during the third quarter of 2012. One of the primary objectives of the Stakeholder process was to avoid the point of no return for any potential option. Receiving a decision on the request for a CPCN by the third quarter will ensure that the Unit 12 retrofit option is not lost due to passage of time. The assumptions underlying the economic analysis are premised upon receiving a Commission Order by that time. He explained that there is a point of no return at which NIPSCO will not have time or it would be cost prohibitive to build an FGD because the schedule would be too constrained. This fact was acknowledged during the Stakeholder process and understood by all.

Mr. Hooper responded to Mr. Ladd's suggestion that there was a risk Unit 12 could not comply with Utility MACT after installation of the environmental controls. Mr. Hooper testified that the dry FGD technology combined with a bag house has been installed on many coal units throughout the United States and is proven to reduce emissions of SO_2, mercury and particulate matter to a level in compliance with the upcoming environmental regulations.

Mr. Hooper also disagreed that there is a "significant" risk of cost increases. With the experience the project management team has achieved with Schafer Unit 14, the risk of cost increases for Unit 12 is significantly reduced. Mr. Hooper indicated that he is comfortable stating the cost estimate has an associated range of +/- 40% and that this is an appropriate range to use for purposes of analyzing whether a CPCN should be granted. While a significant amount of engineering work would still be required to move to a budgetary cost estimate, the valuable knowledge and experience that NIPSCO has already gained allows NIPSCO to significantly reduce uncertainty from the overall cost estimate. In discovery and on cross-examination, Mr. Hooper further refined the estimate and in fact committed to a 25% cap on cost overruns for the Phase III Projects, which we will describe in further detail later.

Mr. Hooper also testified concerning the risk associated with the St. Joseph project. He testified that the construction risk associated with a long term power purchased agreement for a yet-to-be-constructed facility could never be fully mitigated by a security bond, letter of credit, or other performance security. He detailed some of the risks and unanswered questions associated with the SJEC project.

iii. Phase III Rebuttal Testimony of Kurt W. Sangster. Mr. Sangster also testified in rebuttal, specifically with regard to the change from SCR duct burners to WSB technology. He also testified regarding the need to install SCR reheat technology for NOx removal regardless of whether a CPCN is issued for the FGD facility. Mr. Sangster testified that the Consent Decree requires a cap on the 30-day rolling average emission rate for NOx and a progressively more stringent 360-day rolling emission rate. SCR facilities remove NOx but can only operate within certain minimum temperature ranges. This minimum range is not reached during periods of low load operation or start up or shut down. As a result, SCR reheat technology is required. According to Mr. Sangster even if a CPCN is not issued for the FGD, NIPSCO would still need to install reheat technology in order to ensure that it can comply with the more stringent 360-day rolling average emission limits that become effective December 31, 2013 under the Consent Decree. Under that scenario, Unit 12 could continue to operate until it is forced to retire under the Utility MACT timeline. The reheat technology is needed regardless of the decision on the FGD.

Mr. Sangster also described the change from duct burners to WSB. NIPSCO originally selected duct burners as the preferred technology for the Bailly Units but has continued to evaluate operating characteristics in associated NOx emission levels for the remainder of its generation fleet. The Bailly Units are different because of their very long start up durations and therefore had the most immediate need for SCR technology. With Schafer Unit 14 and Michigan City Unit 12, NIPSCO studied the number and duration of startups and determined that uncontrolled NOx emissions pose a less significant problem for these units than for Bailly. NIPSCO retained Black & Veatch in July 2011 to conduct preliminary engineering regarding options. WSB was identified as a possible option, which NIPSCO has continued to study. Further review and analysis were conducted to the point where NIPSCO is now comfortable that the WSB technology is appropriate and will allow the project to be completed at a lower cost. The estimated cost for WSB technology at Unit 12 is $7,017,700 and the estimated operating and maintenance cost is $20,000 per year. NIPSCO is modifying its request in this case such that the requested CPCN and all other associated requested relief relating to duct burners for Unit 12 now relate to the more cost effective WSB technology for Unit 12. According to Mr. Sangster, WSB technology indirectly reduces NOx emissions and will allow NIPSCO to continue operating Unit 12 longer than if WSB were not installed. There is a high likelihood of success for the proposed technology and the cost and feasibility of retiring Unit 12 has been studied in depth. He stated that WSB is an advanced technology designed to maintain the temperature of the flue gas to 617 degrees F going into the Unit 12 SCR, which will allow the Unit 12 SCR to operate and reduce NOx emissions during periods of low load operation when otherwise the temperature in the SCR catalyst would be too low for the SCR to operate. He also stated the WSB technology was not in general commercial use at the same or greater scale in newer existing facilities as of January 1, 1989 and it increases the fuel flexibility allowing Michigan City 12 a blend of approximately 30% Illinois basin coal. According to Mr. Sangster the request for a CPCN for WSB technology is in the public interest and public convenience and necessity will be served by the WSB technology.

iv. Phase III Rebuttal Testimony of Cecelia Largura. Ms. Largura testified on rebuttal regarding NIPSCO's planning process as related to the economic analysis in the Stakeholder process, the reasonableness of commodity price assumptions, fuel diversity and SCR reheat technology. She explained the overall goal of long term planning. NIPSCO's planning process attempts to bind the uncertainties through sensitivity analysis. This planning process culminated in the 2011 IRP which addresses the most likely contingencies. The 2011 IRP was then used as the starting point for the Stakeholder analysis. She explained that a range of natural gas price forecasts was used in the IRP, the basis for which was provided by PIRA Energy Group. This included a low market sensitivity, a high market sensitivity and a base case which is deemed to be the most likely to occur. The IRP also assumed a future with a carbon cap and trade program commencing in 2020.

Ms. Largura compared the issues over gas price forecasting in this case to the evidence the Commission heard in *Indiana Finance Authority and Indiana Gasification, LLC*, Cause No. 43976 (IURC Nov. 22, 2011) ("SNG Order"). The Commission heard considerable evidence about price forecasts, shale gas reserves, shale gas economics, and the market for natural gas. Ms. Largura indicated that the Commission ultimately concluded gas price forecasts are inherently unpredictable and volatile. She testified that the same arguments and evidence are present here. That is why the 2011 IRP includes a low market and a high market sensitivity around the base case.

Ms. Largura also explained the impact of carbon regulation on gas forecasts. The implementation of a carbon cap and trade program will affect coal units greater than gas units. The result will be more natural gas generation displacing coal generation, resulting in higher demand for natural gas and applying upward price pressure on natural gas. None of the forecasts can reliably predict the magnitude of this impact. She noted that for the SJEC bid to ever generate a benefit we must assume both a carbon cap and trade program and the low price forecast. She also outlined the other factors that impact commodities forecasts.

With respect to fuel diversity, she indicated that NIPSCO's IRP already considers the benefits of diversity. NIPSCO seeks to identify a plan that is not only the least cost solution for customers but a plan that minimizes customers' exposure to market and economic certainties. She noted that it is ironic that SJEC would argue their bid should receive value based upon diversity. The decision to stop burning coal at Unit 12 is irreversible and existing coal fire plants are irreplaceable. Coal fire plants will be retired and replaced with natural gas plants. Indeed, the 2011 IRP calls for the retirement of Bailly during the IRP horizon and replacement of its capacity with capacity from a CCGT unit. The SJEC facility could be an alternative in this regard when it is time to make a decision regarding Bailly. Gas plants will be built when generation is needed, and so "preemptive surrender" of a coal plant before it is necessary actually serves to decrease diversity. Finally, she responded to Witness Ladd's criticism that duct burners were not included in the refit economic analysis. She noted first that the magnitude of this issue has been greatly reduced by the switch to WSB technology, which is lower in cost. She also noted that not installing this equipment would mean that Unit 12 would need to be replaced as early as December 31, 2013 in order to comply with the Consent Decree. NIPSCO would have to rely on the market which would put customers at too great a risk.

v. **Phase III Rebuttal Testimony of Charles A. Adkins.** Mr. Adkins also testified on rebuttal that there is no need for further study because all of the additional analysis Witness Ladd has requested has already been completed as a part of the Stakeholder process. Only under the low case scenario and with a carbon future commencing in 2020 does the SJEC bid for a PPA, which is significantly larger in size than Michigan City 12, produce a net present value benefit in terms of revenue requirements. That benefit only commences in the outlier years of the analysis and is due to carbon constraints. He noted this is revealed by the year-by-year analysis. Until 2019, a PPA with a large configuration is a net cost to NIPSCO customers every year. Then in the period 2020 to 2032, after the implementation of a carbon cap and trade program, those losses begin to offset. It is only in 2022 that the benefits would actually begin to exceed the earlier years of costs, and these benefits are primarily due to increased dispatching and off-system sales. Not only is there inherent unpredictability and volatility in the market for natural gas, Mr. Adkins testified there is too much political and economic uncertainties surrounding carbon emissions. He testified that these are very large bets that to ask NIPSCO customers to place, bets that Witness Dauphinais on behalf of the Industrial Group does not want to place. If carbon regulation is delayed or not forthcoming, the SJEC bid would never generate the net present value benefit even under the assumption of low gas prices for the indefinite future.

6. **Commission Discussion and Findings.**

A. **Clean Coal Technology, Qualified Pollution Control Technology, Clean Energy Projects.** Petitioner has requested relief under the following Indiana statutes: Ind. Code Chapter 8-1-8.7, Ind. Code Chapter 8-1-8.8, Ind. Code § 8-1-2-6.7, and Ind. Code § 8-1-2-6.8. As an initial matter, we must determine whether the Phase III Projects constitute "clean coal technology" under Ind. Code Chapter 8-1-8.7, Ind. Code § 8-1-2-6.7, Ind. Code § 8-1-2-6.8 and Ind. Code § 8-1-8.8-3, "qualified pollution control technology" under Ind. Code § 8-1-2-6.8, and "clean energy projects" under Ind. Code ch. 8-1-8.8.

i. **Clean Coal Technology under Ind. Code § 8-1-8.7-1, Ind. Code § 8-1-2-6.7, Ind. Code § 8-1-2-6.8, and Ind. Code § 8-1-8.8-3.** The term "clean coal technology" or CCT is defined slightly differently by the various statutes, but all are generally consistent. Pursuant to Ind. Code § 8-1-8.7-1, CCT means:

> [A] technology (including precombustion treatment of coal): (1) that is used in a new or existing electric generating facility and directly or indirectly reduces airborne emissions of sulfur or nitrogen based pollutants associated with the combustion or use of coal; and (2) that either: (A) is not in general commercial use at the same or greater scale in new or existing facilities in the United States as of January 1, 1989; or (B) has been selected by the United States Department of Energy for funding under its Innovative Clean Coal Technology program and is finally approved for such funding on or after January 1, 1989.

Ind. Code § 8-1-8.7-1.[8]

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[8] Under Ind. Code § 8-1-2-6.8, CCT also includes technology that "directly or indirectly reduces airborne emissions of mercury . . . or other regulated air emissions associated with the combustion or use of coal". For the purpose of

NIPSCO Witnesses Sangster and Carmichael testified that the Phase III Projects will be installed at NIPSCO's Michigan City Unit 12 generating facility and will directly or indirectly reduce the emissions of SO_2 and NOx from flue gas created during the combustion of coal. Mr. Sangster testified that none of the Multi-Pollutant Compliance Plan projects were commercially available prior to January 1, 1989, and that the projects will reduce sulfur- and nitrogen-based pollutants in a more efficient manner than conventional technologies in general use as of January 1, 1989. No party disputed this testimony.

Based on our review of the record evidence, we find that the Phase III Projects constitute "clean coal technology" as defined in Ind. Code § 8-1-8.7-1, Ind. Code § 8-1-2-6.7, Ind. Code § 8-1-2-6.8 and Ind. Code § 8-1-8.8-3.

ii. <u>Qualified Pollution Control Property under Ind. Code § 8-1-2-6.8</u>. Ind. Code § 8-1-2-6.8 defines "qualified pollution control property" ("QPCP") as "an air pollution control device on a coal burning energy generating facility or any equipment that constitutes clean coal technology that has been approved for use by the commission and that meets applicable state or federal requirements."

Mr. Sangster testified that NIPSCO could not achieve compliance with the Consent Decree or with the various requirements of several federal environmental regulations using conventional technologies in general use on January 1, 1989. NIPSCO Witnesses Carmichael and Sangster testified that NIPSCO must install FGD and WSB technology and CPMs on Michigan City Unit 12 to comply with the requirements of the Consent Decree and Utility MACT. No party disputed this testimony.

Based on our review of the record evidence, we find that the Phase III Projects are CCT designed to meet applicable federal and state environmental laws and regulations. We find that the proposed Phase III Projects will allow for the continued burning of coal in Petitioner's generating units by enhancing their ability to cost-effectively comply with applicable state and federal environmental regulations. Accordingly, we find that the Phase III Projects constitute "qualified pollution control property" as defined in Ind. Code § 8-1-2-6.8.

Ind. Code Chapter 8-1-8.8, CCT is defined as "a technology (including precombustion treatment of coal): (1) that is used in a new or existing energy production or generating facility and directly or indirectly reduces or avoids airborne emissions of sulfur, mercury, or nitrogen oxides or other regulated air emissions associated with the combustion or use of coal; and (2) that either: (A) was not in general commercial use at the same or greater scale in new or existing facilities in the United States at the time of enactment of the federal Clean Air Act Amendments of 1990 (P.L.101-549); or (B) has been selected by the United States Department of Energy for funding or loan guaranty under an Innovative Clean Coal Technology or loan guaranty program under the Energy Policy Act of 2005, or any successor program, and is finally approved for such funding or loan guaranty on or after the date of enactment of the federal Clean Air Act Amendments of 1990 (P.L.101-549).

iii. Clean Energy Projects under Ind. Code Chapter 8-1-8.8. The term "clean energy projects" include, among others, "[p]rojects to provide advanced technologies that reduce regulated air emissions from existing energy production or generating plants that are fueled primarily by coal or gases from coal from the geological formation known as the Illinois Basin. . . . ." Ind. Code § 8-1-8.8-2(1)(B).[9]

We have already concluded that the Phase III Projects constitute CCT as defined by Ind. Code § 8-1-8.8-3. Mr. Sangster testified that the Phase III Projects will be installed on NIPSCO's Michigan City Unit 12 electric generating facility and will reduce SO_2 and NOx emissions created during the combustion of coal. He testified that the Multi-Pollutant Compliance Plan projects will reduce sulfur and nitrogen based pollutants in a more efficient manner than conventional technologies in general use as of January 1, 1989. Further, Mr. Sangster testified that the FGD and WSB projects in combination will increase fuel flexibility for Michigan City Unit 12. We find that the Phase III Projects constitute advanced technologies that reduce regulated air emissions from existing energy generating plants and therefore find the Phase III Projects constitute "Clean Energy Projects" as defined in Ind. Code § 8-1-8.8-2.

B. CPCN for use of CCT under Ind. Code Ch. 8-1-8.7. Petitioner requests the issuance of a CPCN for each of the Phase III Projects pursuant to Ind. Code ch. 8-1-8.7. Indiana Code § 8-1-8.7-3(b) states: "The commission shall issue a certificate of public convenience and necessity under subsection (a) if the commission finds that a clean coal technology project offers substantial potential of reducing sulfur or nitrogen based pollutants in a more efficient manner than conventional technologies in general use as of January 1, 1989." In order to grant Petitioner's request for a CPCN, we must make a finding on each of the factors described in Ind. Code § 8-1-8.7-3(b), including the dispatching priority of the facility to the utility. Ind. Code § 8-1-8.7-4(b).

i. CPCN Factors.

(1) The costs for constructing, implementing, and using clean coal technology compared to the costs for conventional emission reduction facilities.

Mr. Sangster provided evidence that the CCT included in the Multi-Pollutant Compliance Plan will reduce sulfur and nitrogen based pollutants in a more efficient manner than conventional technologies in general use as of January 1, 1989 and that NIPSCO could not achieve compliance with the Consent Decree or with the various requirements of CAIR, CATR and Utility MACT using conventional technologies in general use on January 1, 1989. Moreover, Mr. Carmichael and Mr. Sangster presented evidence that the Unit 12 FGD and CPM

[9] The provisions of the state environmental statutes providing favorable regulatory treatment to projects using Indiana coal have been held to be an unconstitutional interference with interstate commerce, but severable from the rest of the statutes which remain valid. *General Motors Corp.* v. *Indianapolis Power & Light Co.,* 654 N.E.2d 752, 763 (Ind. Ct. App. 1995); *Alliance For Clean Coal* v. *Bayh,* 72 F.3d 556 (7th Cir. 1995), *See also S. Ind Gas and Electric Co.,* Cause No. 41864, at 7 (Aug. 29, 2001); *N Ind Pub. Servo Co.,* Cause No. 42150, at 5 n. 3 (Jan. 26, 2002); *Indianapolis Power and Light Co.,* Cause No. 42170, at 5 n.1 (Jan. 14, 2002). We will accordingly not rely upon such statutory provisions as a prerequisite for approval of a certificate of clean coal technology, to obtain QPCP status or to receive any other authority.

are necessary to comply with the Consent Decree and Utility MACT. The Unit 12 WSB is a cost-effective means to reduce regulated emissions. We find that conventional emission reduction facilities are not an option for NIPSCO to achieve the emissions reductions required by the EPA Regulations. As a result, we find that NIPSCO's choice to construct, install, and use the Phase III Projects over conventional emission reduction technology is reasonable.

(2) Whether a clean coal technology project will also extend the useful life of an existing electric generating facility and the value of that extension.

Mr. Sangster testified that the projects included in the Multi-Pollutant Compliance Plan will extend the useful life of NIPSCO's existing generating facilities because, without these technologies, NIPSCO could not operate the facilities and achieve compliance with the Consent Decree or with the various requirements of CAIR, CATR and Utility MACT. Specifically, the record evidence demonstrates that without the Unit 12 FGD and CPM, NIPSCO could not comply with the Consent Decree or Utility MACT. Although SJEC's Witness Ladd questioned whether the Unit 12 FGD will allow NIPSCO to continue operating in compliance with EPA's final Utility MACT rule, NIPSCO provided evidence that Dry FGD technology combined with a baghouse (which NIPSCO's proposed project includes) has been installed on many coal units throughout the United States and is proven to reduce emissions of SO_2, mercury, and particulate matter. Therefore, we find that the Phase III Projects will extend the useful economic life of NIPSCO's generating facilities.

(3) The potential reduction of sulfur and nitrogen based pollutants achieved by the proposed clean coal technology system.

(4) The reduction of sulfur and nitrogen based pollutants that can be achieved by conventional pollution control equipment.

Mr. Sangster testified that the installation of FGD, WSB and CPM technology on Michigan City Unit 12 will remove SO_2 and NOx from flue gas created during the combustion of coal that is formed when the sulfur that is a minor constituent of coal is oxidized during the combustion of coal with air. Mr. Sangster also testified that the FGD system will be required to achieve the SO_2 removal efficiency of 97%. No party disputed NIPSCO's evidence that the Phase III Projects are necessary to allow NIPSCO to reduce its air emissions sufficiently to comply with the EPA Regulations, including EPA's final Utility MACT. Accordingly, we find the Phase III Projects will provide significant reduction in SO_2 and NOx emissions.

(5) Federal sulfur and nitrogen based pollutant emission standards.

Based on the extensive evidence presented by NIPSCO and the OUCC regarding the applicable federal sulfur- and nitrogen-based pollutant emissions standards (including EPA's final Utility MACT), we find that the Phase III Projects are a reasonable and necessary means to enable NIPSCO to comply with federal sulfur- and nitrogen-based pollutant emission standards.

(6) The likelihood of success of the proposed project.

Mr. Sangster testified that without the Unit 12 FGD and CPM, NIPSCO could not comply with the Consent Decree and Utility MACT. NIPSCO witness Hooper provided testimony regarding the measures NIPSCO has taken to ensure that the Phase III Projects are managed prudently. Further Mr. Hooper provided testimony regarding what NIPSCO is doing and will do to control costs, remain on time and on budget and hold its contractors accountable as the Phase III Projects progress. Substantial record evidence supports our finding that the measures described by Mr. Hooper should work to manage properly the Phase III Projects to successful completion. Based on the record evidence, we find the Phase III Projects will allow NIPSCO to achieve compliance with the EPA Regulations and the likelihood of success in the implementation and utilization of the Phase III Projects is high.

(7) The cost and feasibility of the retirement of an existing electric generating facility.

Phase III dealt extensively with the cost and feasibility of retiring Michigan City Unit 12. We will address this particular finding in conjunction with our discussion and finding on the public convenience and necessity. For the reasons we describe therein, we ultimately find that the cost and feasibility of retiring Michigan City Unit 12 and constructing or purchasing equivalent capacity is not a cost-effective alternative to installation of the proposed Phase III Projects under the reasonable assumptions used in the decision-making analysis presented.

(8) The dispatching priority for the facility utilizing clean coal technology, considering direct fuel costs, revenues and expenses of the utility, and environmental factors associated with byproducts resulting from the utilization of the clean coal technology.

By its Verified Petition, NIPSCO requested authority to perform dispatch of its generation units in a manner necessary to comply with the requirements of the Consent Decree or other environmental regulations or requirements and that the Commission declare such procedures to be in compliance with current and future dispatch parameters relating to the recovery of fuel costs.

Mr. Carmichael testified that the projects included in NIPSCO's Multi-Pollutant Compliance Plan are designed to achieve the emission limitations set forth in the Consent Decree as well as provide for a base level of additional reductions that will be required under existing phased in and projected future EPA regulations and requirements but that during certain situations it may be necessary for the NIPSCO units to change priority of dispatch, short term generation levels, or take an outage to maintain compliance with emission limitations. Mr. Carmichael testified that if a piece of pollution control equipment malfunctions, an outage may be needed to repair the malfunction. Mr. Sangster testified that at times it may be necessary for NIPSCO to re-dispatch unit operations in order to achieve compliance with environmental requirements and that if necessary, NIPSCO will dispatch accordingly. However, there is no evidence to suggest that the Phase III Projects will significantly alter the normal dispatching priority for Michigan City Unit 12.

NIPSCO's request is consistent with the Commission's recognition that Indiana utilities may sometimes need to change their priority of dispatch or short term generation levels for environmental purposes such as environmental derates. *See* April 23, 2008 Order in Cause No. 43414 (Joint Petition of Indianapolis Power & Light Company, Southern Indiana Gas and Electric Co. d/b/a/ Vectren Energy Delivery of Indiana, Inc., and the Indiana Office of Utility Consumer Counselor for Approval of Settlement Establishing a Mechanism for the Recovery of Purchased Power Costs); March 23, 2005 Order in Cause No. 42770 (Joint Petition of Indianapolis Power & Light Company, Southern Indiana Gas and Electric Co. d/b/a/ Vectren Energy Delivery of Indiana, Inc., and the Indiana Office of Utility Consumer Counselor for Approval of Settlement Establishing a Mechanism for the Recovery of Purchased Power Costs); May 26, 2004 Order in Cause No. 42616 (Joint Petition of Indianapolis Power & Light Company and the Indiana Office of Utility Consumer Counselor for Approval of Settlement Establishing a Mechanism for the Recovery of Purchased Power Costs); and May 26, 2004 Order in Cause No. 42605 (Joint Petition of Southern Indiana Gas and Electric Co. d/b/a/ Vectren Energy Delivery of Indiana, Inc., and the Indiana Office of Utility Consumer Counselor for Approval of Settlement Establishing a Mechanism for the Recovery of Purchased Power Costs).

Based on the record evidence, we find it is possible that the dispatch order of NIPSCO's generation units may change as a result of installation of the Multi-Pollutant Compliance Plan projects due to potential changes in operating expenses, but the evidence does not show that the Phase III Projects will significantly impact the normal dispatch priority of Michigan City Unit 12. NIPSCO, as a responsible generating plant operator, must comply and should be supported in its pursuit to comply with the state and federal environmental regulations. Therefore, we find that NIPSCO's request to perform dispatch of its generation units in a manner necessary to comply with the requirements of the Consent Decree, environmental regulations, or other requirements is reasonable.

(9) Any other factors the commission considers relevant, including whether the construction, implementation, and use of clean coal technology is in the public's interest.

This factor will be discussed in conjunction with our finding on public convenience and necessity.

ii. <u>CPCN Findings</u>. In addition to the above findings on the nine factors described in Ind. Code § 8-1-8.7-3(b), as required by Ind. Code § 8-1-8.7-4(b)(4), we must address the three remaining required findings set forth in Ind. Code § 8-1-8.7-4(b)(1)-(b)(3). We note that a finding that a project is in the public convenience and necessity (*see* IC 8-1-8.7-4(b)(1)) and the approval of the estimated costs for that project (*see* IC 8-1-8.7-4(b)(2)) are separate and distinct components of an approved CPCN. With respect to public convenience and necessity, it is appropriate to consider the project cost with its inherent range of accuracy used to determine a project's viability, which differs from our review of the present cost estimate for which a utility seeks approval.

(1) A finding that the public convenience and necessity will be served by the construction, implementation, and use of clean coal technology.

Phase III was dedicated to the question of whether refitting Unit 12 with the Phase III Projects serves the public convenience and necessity. The evidence we heard analyzed whether there exists a better alternative to compliance with the Consent Decree and EPA Regulations than the Phase III Projects. Our decision rests upon our analysis of multiple factors, including: (1) uncertainty of natural gas price forecasts; (2) the relative importance of maintaining coal in the Indiana generation fleet for as long as possible; and (3) risk and uncertainty between the two alternatives. As we will explain, we ultimately find that refitting Unit 12 with the Phase III Projects serves the public convenience and necessity.

The Unit 12 Projects will allow for continued use of coal to generate electricity at Unit 12. Further, the decision to retire Unit 12 would be an irreversible decision. As Industrial Group witness Dauphinais points out, Unit 12 and other large, efficient coal-fired generating stations are "somewhat irreplaceable." The evidence supports that Unit 12 is an efficient generation resource and we are not inclined, as Mr. Shambo described, to implement a "pre-emptive surrender" of one of Indiana's efficient coal-fired facilities simply because other alternatives may be cost effective under certain future scenarios. In this case, based on the analyses provided, we believe that faced with uncertainty regarding the future market prices of commodities, it is better to maintain the option to run Unit 12 on coal rather than to permanently foreclose this option; refitting Unit 12 with the Phase III Projects is the only way to maintain coal as an option for this unit.

In this case we have also reviewed the extensive consideration of the relative risk of refitting Unit 12 with the Phase III Projects versus replacing Unit 12. When the construction cost price cap on the Phase III Projects is considered, we find the relative risk favors the Phase III Projects under both the Base Case and even the Low Case scenarios. We recognize that a range of reasonableness exists for the inputs into any decision-making analysis and the range vetted by the parties to this proceeding is wide. As noted by Mr. Adkins, the SJEC bid only produces a net benefit if there is carbon regulation and if natural gas prices remain low. Even then, the benefit is only in the outlier years, and it is a much smaller benefit for the customers than the costs they would bear should either the carbon regulation or low gas price assumptions trend the other direction.

Perhaps the most significant risk that we have heard repeated throughout all three phases of this proceeding is the risk of construction cost increases. The cap on cost that NIPSCO offered during the cross-examination of Mr. Hooper greatly reduces and addresses this risk. Except upon the occurrence of a Force Majeure Event,[10] NIPSCO has agreed not to seek recovery of

[10] For purposes of this commitment, NIPSCO has defined the term "Force Majeure Event" as including, but not limited to, the following: acts of God; acts of war or terrorism; extended labor dispute resulting in a work stoppage; orders by a government official, government agency, other regulatory authority, or a regional transmission organization, acting under and authorized by applicable law, that directs NIPSCO to halt work on the Project or materially change the scope of the Project; failure of a permitting authority to issue a necessary permit in a timely fashion where the failure of the permitting authority to act is beyond the control of NIPSCO and NIPSCO has taken all steps available to it to obtain the necessary permit, including, but not limited to: submitting a complete permit

Unit 12 Projects capital costs in excess of $307,990,875 not including AFUDC (i.e., 25% over initial cost estimate of $246,392,700). If any Force Majeure Event occurs that may cause NIPSCO to incur extra cost to complete the engineering and construction of the Unit 12 Projects despite NIPSCO's best efforts to control the costs as to which NIPSCO intends to assert a claim of Force Majeure, NIPSCO has committed to (i) provide notice to the OUCC and other interested stakeholders if it anticipates that it might incur extra cost as a result of a Force Majeure Event and (ii) file a Notice of Force Majeure Event with the Commission under this Cause as soon as practicable following the date NIPSCO first knew, or by the exercise of due diligence should have known, but in no event more than 30 calendar days following, that the event caused or may cause such extra costs. In this notice, NIPSCO has committed to describe the anticipated extra costs, the cause or causes of the extra costs, all measures taken or to be taken by NIPSCO to prevent or minimize the extra costs, the schedule by which NIPSCO proposes to implement those measures, and NIPSCO's rationale for attributing such extra costs to a Force Majeure Event. Mr. Baatz testified on behalf of the OUCC that, with this commitment being made, he now agrees the public convenience and necessity supports the issuance of the requested CPCN for the Phase III Projects.

We agree with Mr. Baatz that NIPSCO's commitment, coupled with the balance of the other risk factors under consideration, favors deployment of the Phase III Projects. However, we note that under our public interest review of the Phase III Projects, it is appropriate for the Commission to tie a finding of public convenience and necessity, whether implicitly or explicitly, to the cost estimate (with an appropriate range of accuracy) and underlying analysis provided by the petitioning utility in order to determine the viability of the proposed project. This is especially true in this case, in which other options were comparable in cost at the upper ranges of Phase III cost estimates and lower ranges of natural gas pricing.

As we explained in our Phase I Order in this Cause, "the initial granting of a CPCN depends in large part upon the economic efficacy of a proposed project, and as such, the initial cost estimates are a significant factor in the Commission's decision making process." *NIPSCO*, Cause No. 44012 Phase I Order, at 18 (IURC Dec. 28, 2011). NIPSCO's commitment to cap the Phase III recovery to a 25 percent allowance over its cost estimate for which it seeks approval herein (excluding AFUDC) is consistent with this Commission's authority to determine appropriate cost recovery under our public interest review. We find that public convenience and necessity is met so long as the final cost of the Phase III Projects does not exceed $307,990,875 (excluding AFUDC), subject to our ongoing review under Ind. Code ch. 8-1-8.7. As noted in subsection (2) below, through this Order we are only approving the recovery of NIPSCO's estimated cost of $246,392,700.

Based on the record evidence and our analysis of the factors set forth in Ind. Code § 8-1-8.7-3(b), we find that the public convenience and necessity will be served by NIPSCO's

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application; responding to requests for additional information by the permitting authority in a timely fashion; and accepting lawful permit terms and conditions after expeditiously exhausting any legal rights to appeal terms and conditions imposed by the permitting authority; issuance of a Phase III Order in Cause No. 44012 after September 30, 2012 granting NIPSCO's request for a CPCN which results in a cost increase for the Unit 12 Projects in excess of the cap; or any causes which are not within the control of NIPSCO, and which by the exercise of reasonable diligence, NIPSCO is unable to prevent.

construction, implementation and use of the Phase III Projects based on the estimated cost, and range of accuracy and the associated analysis, and cap provided by NIPSCO.

(2) Approval of the Estimated Costs.

Petitioner requests approval of the cost estimates for the Phase III Projects set forth in Response to IURC Request 3-1 (Petitioner's Exhibit No. III-1). Those costs, excluding AFUDC, are Unit 12 FGD ($239,000,000), Unit 12 WSB SCR Reheat Project ($7,017,700) and Unit 12 Continuous Particulate Monitors ($375,000). The details of these cost estimates are set forth in Petitioner's Exhibits Nos. KWS-1, KWS-3 and KWS-R2-III.

Indiana Code § 8-1-8.7-4(a) states: "As a condition for receiving the certificate required under section 3 of this chapter, an applicant must file an estimate of the cost of constructing, implementing, and using clean coal technology and supportive technical information in as much detail as the commission requires." In addition, before we may grant Petitioner a CPCN for the Phase III Projects, we must approve the estimated costs. Ind. Code § 8-1-8.7-4(b).

The referenced exhibits to Mr. Sangster's testimony, supplemental testimony, and rebuttal testimony provide the details of the cost estimates for the Phase III Projects. NIPSCO also provided evidence regarding the anticipated O&M expenditures to support the QPCP and CCT projects included in the Multi-Pollutant Compliance Plan once they are in service on Petitioner's Exhibits Nos. KWS-3 as revised by Petitioner's Exhibit No. KWS-R. Mr. Sangster testified that the estimates were developed after completion of the preliminary engineering by Sargent & Lundy and are based on the defined scope determined by preliminary engineering and numerous actual project costs for similar scope.

Although some of the parties questioned the range of accuracy associated with these cost estimates, Mr. Hooper clarified that NIPSCO believes a +/- 40% range of accuracy is the appropriate range to use for the purpose of analyzing whether a CPCN for the Unit 12 FGD project should be granted. He testified that NIPSCO is comfortable with this +/- 40% range notwithstanding the fact that the amount of engineering that has been completed for the Unit 12 FGD project technically yields only an "order of magnitude" cost estimate with an associated +100/-50%. Finally, Mr. Hooper testified that NIPSCO is comfortable with this +/- 40% range based upon prior experience, independent order of magnitude cost estimates from two sources, and commodity pricing experience gained during the current FGD project at Schahfer Units 14 and 15. Furthermore, except upon the occurrence of a Force Majeure Event, NIPSCO has agreed not to seek recovery of Unit 12 Projects capital costs in excess of $307,990,875 not including AFUDC (i.e., 25% over initial cost estimate of $246,392,700). Based upon our approval herein, NIPSCO must seek a modification of its CPCN for any increase above $246,392,700 (excluding AFUDC), pursuant to Ind. Code ch. 8-1-8.7.

We note that while NIPSCO has committed that it will not seek recovery of capital costs above a certain cap, NIPSCO is not requesting approval at this time of anything other than $246,392,700 for the Phase III Projects plus appropriate AFUDC. We find that substantial record evidence demonstrates that NIPSCO's cost estimates for the Phase III Projects of Unit 12 FGD ($239,000,000), Unit 12 WSB SCR Reheat Project ($7,017,700), and Unit 12 CPMs ($375,000) (all excluding AFUDC) are reasonable and should be approved.

> **(3) A finding that the facility where the clean coal technology is employed: (A) utilizes and will continue to utilize Indiana coal as its primary fuel source; or (B) is justified, because of economic considerations or governmental requirements, in utilizing non-Indiana coal; after the technology is in place.**

As discussed in footnote 7 above, we will not use the Indiana coal requirement as a prerequisite for approval of a certificate of CCT, to obtain QPCP status, or to receive any other authority.

Based on our review of the record evidence, we find that the Phase III Projects offer substantial potential of cost effectively reducing sulfur or nitrogen based pollutants in a more efficient manner than conventional technologies in general use as of January 1, 1989. We have also considered the other enumerated factors set forth in Ind. Code § 8-1-8.7-3 and made the required findings under Ind. Code § 8-1-8.7-4(b). Accordingly, we find that Petitioner's request for a CPCN for the Phase III Projects, at the proposed estimated costs of $239,000,000 for the FGD, $7,017,700 for the WSB, and $375,000 for the CPM for which it can rely upon for cost recovery, should be granted.

C. Approval of Clean Energy Projects under Ind. Code Ch. 8-1-8.8. Indiana Code § 8-1-8.8-11 provides that "[a]n eligible business must file an application to the commission for approval of a clean energy project" and that "[t]he commission shall encourage clean energy projects by creating [certain] financial incentives for clean energy projects, if the projects are found to be reasonable and necessary."

Mr. Sangster testified that installation and use of the projects proposed in the Multi-Pollutant Compliance Plan will allow NIPSCO to continue to meet demands made upon it for electric power, while doing so in an environmentally compliant and cost effective manner. Mr. Sangster and Mr. Carmichael testified that the Unit 12 FGD and CPM are necessary to comply with the Consent Decree and Utility MACT.

As we discussed above, the Phase III Projects constitute "clean energy projects" under Ind. Code § 8-1-8.8-2. Based on our review of the evidence, we find that the Phase III Projects are a reasonable and necessary cost-effective means to reduce SO_2 and NOx emissions from NIPSCO's Michigan City Unit 12. We therefore approve of the Phase III Projects and find that they are eligible for the financial incentives set forth in Ind. Code Ch. 8-1-8.8.

As a result of being eligible for the financial incentives under Ind. Code Ch. 8-1-8.8, Petitioner requests among other things authorization to utilize CWIP ratemaking treatment for clean energy projects (and CCT and QPCP) and to recover O&M expenses relating to the Phase III Projects, including depreciation expense, for clean energy projects (and its CCT and QPCP) consistent with and through Petitioner's currently-effective ECRM and EERM. Indiana Code 8-1-8.8-11(a)(1) provides:

> (a) The commission shall encourage clean energy projects by creating the following financial incentives for clean energy projects, if the projects are

found to be reasonable and necessary:

> 1. The timely recovery of costs and expenses incurred during construction and operation of projects described in section 2(1) or 2(2) of this chapter.
>
> * * * * *

Having found that the Phase III Projects constitute clean energy projects that are reasonable and necessary and therefore eligible for the financial incentive set forth in Ind. Code Ch. 8-1-8.8-11(a)(1), we therefore approve NIPSCO's request for timely recovery of costs and expenses incurred during construction and operation of the Phase III Projects consistent with and through Petitioner's ECRM and EERM.

D. Ratemaking Treatment and Depreciation.

i. Ratemaking Treatment - Ind. Code § 8-1-2-6.8 and 170 IAC 4-6. Petitioner requests a finding that the Phase III Projects constitute "qualified pollution control property" and are eligible for the ratemaking treatment described in Ind. Code § 8-1-2-6.8. Specifically Petitioner requests authorization to utilize CWIP ratemaking treatment for CCT and QPCP (and clean energy projects) consistent with and through Petitioner's ECRM. Petitioner also requests authorization to accrue AFUDC related to QPCP prior to CWIP ratemaking treatment or their reflection of such costs in NIPSCO's electric rates and a finding that the Projects are deemed to be under construction until such time the Commission determines that the Projects are used and useful in a proceeding that involves the establishment of new electric basic rates and charges for Petitioner. Petitioner also requests authorization to recover through rates pre-construction costs incurred prior to approval of a Final Order in this proceeding through Petitioner's ECRM.

Indiana Code § 8-1-2-6.8(e) provides: "Upon the request of a utility that begins construction after March 31, 2002, of qualified pollution control property that is to be used and useful for the public convenience, the commission shall for ratemaking purposes add to the value of that utility's property the value of the qualified pollution control property under construction." The Commission's regulations relating to the ratemaking treatment of QPCP under construction further define the ratemaking treatment the Commission may grant for QPCP. *See* 170 IAC 4-6.

Mr. Westerhausen testified that NIPSCO's proposed ratemaking treatment is consistent with that previously approved for NIPSCO's existing NOx Compliance Plan (approved and modified by the Commission in Cause Nos. 42150, 42515, 42737, 42935, 43144, 43371, 43593, 43840, 42150 ECR 17, and 42150 ECR 19) and CAIR/CAMR Compliance Plan (approved and modified by the Commission in Cause Nos. 43188, 43371, 43593, 43840, 42150 ECR 17, and 42150 ECR 19), both of which consisted of CCT and QPCP. Mr. Westerhausen provided evidence that the proposed ratemaking treatment can be readily incorporated into the existing ECRM and EERM filings made periodically with the Commission. Mr. Plantz testified that NIPSCO proposes to commence CWIP ratemaking treatment for the costs of each project once the project has been under construction for at least six months and that this is consistent with past practice using the ECRM. Mr. Plantz testified that NIPSCO proposes to continue recording

AFUDC until such costs are given CWIP ratemaking treatment or are otherwise reflected in base electric rates or the Projects are placed in service, whichever occurs first.

We have already determined that the Phase III Projects constitute "qualified pollution control property" as defined in Ind. Code § 8-1-2-6.8. As a result, we find the Phase III Projects are eligible for the ratemaking treatment described in Ind. Code § 8-1-2-6.8. We find that Petitioner's requests with respect to the ratemaking treatment of its QPCP are consistent with 170 IAC 4-6. We therefore authorize NIPSCO to utilize CWIP ratemaking treatment (including preconstruction costs) and AFUDC treatment for the Phase III Projects consistent with and through Petitioner's ECRM, and we hereby deem the Phase III Projects to be under construction until such time the Commission determines that the Projects are used and useful in a proceeding that involves the establishment of new electric basic rates and charges for Petitioner. We find that NIPSCO should be and hereby is authorized to accrue AFUDC on Phase III Projects costs up to the approved amount, which we have determined to be $246,392,700 for the Phase III Projects. We specifically note that to the extent the Phase III Projects costs exceed the approved amounts, these increased costs and incremental AFUDC associated with project costs above the approved amounts are not approved at this time and would need to be addressed following a public hearing as a part of our ongoing review pursuant to Ind. Code § 8-1-8.7-7.

ii. <u>Depreciation Treatment - Ind. Code § 8-1-2-6.7</u>. Petitioner requests a finding that the Phase III Projects are eligible for the depreciation treatment set forth in Ind. Code § 8-1-2-6.7. Indiana Code 8-1-2-6.7(b) provides:

> The commission shall allow a public or municipally owned electric utility that incorporates clean coal technology to depreciate that technology over a period of not less than ten (10) years or the useful economic life of the technology, whichever is less and not more than twenty (20) years if it finds that the facility where the clean coal technology is employed: (1) utilizes and will continue to utilize (as its primary fuel source) Indiana coal; or (2) is justified, because of economic considerations or governmental requirements, in utilizing non-Indiana coal; after the technology is in place.[11]

We have already found that the Phase III Projects constitute "clean coal technology" as defined in Ind. Code § 8-1-2-6.7. The OUCC recommended that the Phase III Projects be depreciated over a period of twenty (20) years. NIPSCO testified that it would accept the proposed change related to the depreciable life of Phase III Projects, subject to the caveat described by Mr. Shambo in the event future regulations require the premature retirement of Unit 12. Therefore, we find that NIPSCO should be permitted to depreciate each of the Phase III Projects over a period twenty (20) years.

E. <u>Ongoing Review, Semi-Annual Progress Reports and Reporting and Meeting Requirements</u>. As noted previously, Petitioner requests ongoing review of the Phase III Projects pursuant to Ind. Code § 8-1-8.7-7. Petitioner also requests authority to file a semi-

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[11] As discussed above in footnote 7, we will not use the Indiana coal requirement as a prerequisite for determination of NIPSCO's eligibility for the depreciation treatment under Ind. Code § 8-1-2-6.7.

annual progress report (as compared to its current practice of filing an annual progress report) on the status of QPCP in the ECRM as part of every ECRM filing (Cause No. 42150 ECR X).

In accordance with Ind. Code § 8-1-8.7-7, the utility is to submit each year during construction, or at other times as the Commission and the public utility mutually agree, a progress report detailing any revisions in the cost estimates or the planned construction. The Commission must hold a hearing before it may approve or deny a proposed increase in the cost estimate for the implementation, construction or use of the clean coal technology. If the Commission approves the construction and the costs, that approval forecloses subsequent challenges to the inclusion of those costs in the utility's rate base on the basis of excessive cost, inadequate quality control, or inability to employ the technology.

In addition to the statutory ongoing review requirements and the semi-annual progress reporting, the OUCC and Industrial Group provided evidence to support various other reporting and meeting requirements. We find that NIPSCO should comply with the following ongoing reporting and meeting requirements with respect to the Phase III Projects:

(a) Provide to the OUCC, Industrial Group and other interested stakeholders subject to a fully executed non-disclosure agreement or protective order on a monthly basis:

(i) Weekly project status report (Petitioner's Exhibit Nos. MH-S10 (Confidential)),

(ii) Monthly project report (Petitioner's Exhibit Nos. MH-S11 (Confidential)), and

(iii) Senior executive project report (Petitioner's Exhibit Nos. MH-S12 (Confidential));

(b) Provide to the OUCC, Industrial Group and other interested stakeholders subject to a fully executed non-disclosure agreement or protective order on a semi-annual basis a document referred to as the risk register and risk assessment;

(c) Provide as part of its semi-annual progress report filed in Cause No. 42150-ECR-X reports of the cost breakdown as detailed engineering plans progress;

(d) Meet with the OUCC, Industrial Group and other interested stakeholders that have executed a non-disclosure agreement on a quarterly basis or as otherwise needed or mutually agreed on an ad hoc basis to discuss the Multi-Pollutant Compliance Plan projects until the last of the projects goes into service, subject to the understanding that some NIPSCO personnel may need to conduct some of the meetings via conference call, video conference, or other remote means to reduce travel time and accommodate project management staff schedules; and

(e) Permit the OUCC, Industrial Group and other interested stakeholders that have executed a non-disclosure agreement to attend monthly on-site executive Unit 12 FGD Project review meetings or six-month Unit 12 FGD Project risk review meetings subject to attendees providing NIPSCO with advanced notice so that NIPSCO may make the proper security and safety arrangements.

We note that NIPSCO has regularly reported to the Commission on the progress of its approved CCT, QPCP, and clean energy projects by its annual progress reports in Cause Nos. 42515, 42737, 42935, 43144, 43371, 43593, 43840, 42150 ECR 17, and most recently as part of Cause No. 42150 ECR 19. In addition, the ECRM semi-annual proceedings are filed with the Commission, and the Commission must hold a hearing before it may approve or deny a proposed increase in the cost estimates for the implementation, construction or use of the CCT projects. Accordingly, based on the evidence presented in this Cause, we hereby find that the Petitioner's request for ongoing review of the construction of its CCT projects under Ind. Code § 8-1-8.7-7 should be granted and that Petitioner's proposal to file semi-annual progress reports as part of that ongoing review is reasonable and should be approved. Consistent with our August 25, 2010 Order in Cause No. 43526, NIPSCO should continue to file the progress reports as part of its ECRM filings (Cause No. 42150 ECR X). We also find that NIPSCO should comply with the ongoing reporting and meeting requirements enumerated in this section.

F. The Stakeholder Process. Faced with the fact that NIPSCO's Michigan City Unit 12 must either be refit with certain environmental controls or replaced to meet the requirements of the Consent Decree and various federal environmental regulations, NIPSCO worked with Stakeholders to evaluate options for meeting the future resource needs of NIPSCO's customers. This process assisted all interested parties, including the Commission, in establishing the reasonable path forward for customers while balancing costs, risks and policy goals.

NIPSCO and the Stakeholders have expressed their belief that the process was valuable and meaningful, and can be a good model for NIPSCO and other Indiana utilities facing high capital cost investment decisions. However, any endorsement of this collaborative effort should not be interpreted to diminish NIPSCO's sole and exclusive responsibility as the Petitioner to demonstrate that public convenience and necessity requires the proposed retrofit of Michigan City 12, or to otherwise carry the burden of proof as the petitioning utility. The inclusion of Stakeholders in any utility's economic analysis process can be costly to non-utility participants, who do not necessarily have staff or resources that can be dedicated to such an undertaking. Not all Stakeholders will have the ability to engage in such a process, and their participation should not be expected or assumed in any instance. Likewise, the failure of Stakeholders to participate in such processes in the future should not be interpreted as a waiver of their right to assert any objection or raise any issue at a later date. The process should not be used as a replacement for the utility's own careful consideration of appropriate options, and we will still expect to see sufficiently detailed CPCN petitions presented for us to make informed judgments.

Nonetheless, we take note of the Stakeholder process in this instance because the end result in this case is enhanced due to the effort of the Parties. In conclusion, the Stakeholder process utilized in this proceeding is valuable to all and is meaningful for the Commission due to the close collaboration and evaluation by the Stakeholders.

G. Confidentiality. In Phase III of this proceeding, Petitioner filed two motions for protective order and St. Joseph filed one motion, all of which were supported by affidavit showing documents to be submitted to the Commission were trade secret information within the scope of Ind. Code §§ 5-14-3-4(a)(4) and (9) and Ind. Code § 24-2-3-2. The Presiding Officers issued Docket Entries on April 17, 2012 and May 2, 2012, respectively, finding such information to be preliminarily confidential, after which such information was submitted under seal. We find 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. The Phase III Projects shall be and hereby are determined to constitute "clean coal technology" as defined in Ind. Code § 8-1-8.7-1, Ind. Code § 8-1-2-6.7, Ind. Code § 8-1-2-6.8 and Ind. Code § 8-1-8.8-3.

2. Petitioner shall be and is hereby issued a Certificate of Public Convenience and Necessity for the Phase III Projects pursuant to Ind. Code Ch. 8-1-8.7, as set forth herein. This Order constitutes the Certificate.

3. The cost estimates provided by Petitioner in this Cause for the Phase III Projects ($239,000,000 for the Unit 12 FGD, $7,017,700 for the Unit 12 WSB Reheat Project, and $375,000 for the Unit 12 Continuous Particulate Monitor) shall be and are hereby approved.

4. Petitioner's request for ongoing review of the Phase III Projects pursuant to Ind. Code § 8-1-8.7-7 and to file semi-annual progress reports as part of that ongoing review shall be and is hereby approved.

5. The Phase III Projects shall be and are hereby determined to constitute "qualified pollution control property" and are eligible for the ratemaking treatment described in Ind. Code § 8-1-2-6.8.

6. The Phase III Projects shall be and are hereby determined to constitute "clean energy projects" under Ind. Code Ch. 8-1-8.8 that are hereby approved as reasonable and necessary and therefore eligible for the timely recovery of costs and expenses set forth in Ind. Code § 8-1-8.8-11(a)(1).

7. Petitioner shall be and is hereby authorized to utilize CWIP ratemaking treatment, including preconstruction costs incurred prior to the issuance of this Order, for the Phase III Projects consistent with and through Petitioner's Environmental Cost Recovery Mechanism and the Phase III Projects are deemed to be under construction until such time as the Commission determines that the Projects are used and useful in a proceeding that involves the establishment of new electric basic rates and charges for Petitioner.

8. Petitioner shall be and is hereby authorized to depreciate each of the Phase III Projects approved herein over a period of twenty (20) years pursuant to Ind. Code § 8-1-2-6.7.

9. Petitioner shall be and is hereby authorized to accrue AFUDC related to the Phase III Projects prior to CWIP ratemaking treatment or their reflection of such costs in NIPSCO's

electric rates.

10. Petitioner shall be and is hereby authorized to recover O&M expenses and depreciation expenses relating to the Phase III Projects consistent with and through Petitioner's Environmental Expense Recovery Mechanism.

11. Petitioner shall be and is hereby authorized to perform dispatch of its generation units in a manner necessary to comply with the requirements of the Consent Decree or other environmental regulations.

12. Petitioner shall comply with the ongoing reporting and meeting requirements enumerated in Finding Paragraph 6, Section E.

13. The information filed by the Parties in this Cause pursuant to its Motions 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.

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

ATTERHOLT, BENNETT, LANDIS, MAYS AND ZIEGNER CONCUR:

APPROVED: SEP 05 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

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY FOR APPROVAL OF A VOLUNTARY GREEN POWER RIDER PILOT PROGRAM.	)))))	CAUSE NO. 44198 APPROVED:

ORDER OF THE COMMISSION

Presiding Officers:
James D. Atterholt, Chairman
Jeffery A. Earl, Administrative Law Judge

On May 7, 2012 Northern Indiana Public Service Company ("NIPSCO") filed its Verified Petition with the Indiana Utility Regulatory Commission ("Commission") for approval of a voluntary Green Power Rider ("GPR") pilot program. Also on May 7, 2012, NIPSCO prefiled the direct testimony and exhibits of Timothy R. Caister and Curt A. Westerhausen. On July 17, 2012, the Indiana Office of Utility Consumer Counselor ("OUCC") prefiled the testimony of Cynthia M. Armstrong on July 17, 2012. On July 31, 2012, NIPSCO prefiled the rebuttal testimony of Mr. Caister.

Pursuant to notice given and published as required by law, proof of which was incorporated into the record of this Cause, the Commission conducted an Evidentiary Hearing at 9:30 a.m. on August 30, 2012, in Hearing Room 222, 101 West Washington Street, Indianapolis, Indiana. NIPSCO and the OUCC appeared at the hearing and offered their respective prefiled testimony and exhibits into evidence. No member of the general public participated at the hearing.

Having considered the evidence and applicable law, the Commission now finds:

1. **Notice and Jurisdiction.** Due, legal, and timely notice of the public hearing in this Cause was given and published by the Commission as required by law. NIPSCO is a "public utility" within the meaning of Ind. Code § 8-1-2-1(a) of the Public Service Commission Act, as amended. The Commission has jurisdiction over NIPSCO's rates and charges pursuant to Ind. Code § 8-1-2-4 and NIPSCO's schedules of rates pursuant to Ind. Code § 8-1-2-42. Therefore, the Commission has jurisdiction over NIPSCO and the subject matter of this proceeding.

2. **NIPSCO's Characteristics.** NIPSCO is a public utility corporation organized and existing under the laws of the State of Indiana with its principal place of business at 801 East 86th Avenue, Merrillville, Indiana. NIPSCO renders electric and gas 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, distribution, and furnishing of such services to the public. NIPSCO provide electric service to approximately 456,000 residential, commercial, industrial, wholesale, and other customers in all or part of Benton, Carroll, DeKalb, Elkhart, Fulton, Jasper, Kosciusko, LaGrange, Lake, LaPorte, Marshall, Newton, Noble, Porter, Pulaski, Saint Joseph, Starke, Steuben, Warren, and White Counties in northern Indiana.

3. **Relief Requested.** NIPSCO requests approval to offer a voluntary GPR program to its electric customers on a pilot basis through December 31, 2014. NIPSCO's proposal would allow any electric customer to designate 25%, 50%, or 100% of the customer's total monthly electricity usage to be attributable to green power. The proposal would also allow a commercial and industrial ("C&I") customer to designate 5% or 10% of its total monthly electricity usage. NIPSCO proposes a Green Power Rider rate equal to \$0.002163/kWh under proposed Rider 686 for the first six months of the GPR pilot program. No later than six months after the effective date of the proposed Green Power Rider and every six months thereafter, NIPSCO proposes to file a petition for approval of a revised Green Power Rider rate ("GPR Filing").

4. **NIPSCO's Direct Evidence.** Timothy R. Caister, Director of Electric Regulatory Policy, described NIPSCO's GPR pilot program. The program allows customers the option to designate all or some of their electricity usage to be attributable to green power. NIPSCO defines green power as sources that meet the Green-e® National Standard for Renewable Electricity Products in all regions of the United States, which include: solar; wind; geothermal; hydropower that is certified by the Low Impact Hydropower Institute; solid, liquid, and gaseous forms of biomass; and co-firing of biomass with non-renewables. NIPSCO would purchase a sufficient amount of certified renewable energy credits ("RECs") on a dollar-for-dollar pass-through basis to cover all green power designated by its participating customers. NIPSCO's REC purchases would guarantee that participants' electricity usage would be attributable to green power. Mr. Caister stated that Green-e®, a recognized, national organization that ensures RECs are created from the proper sources and are properly claimed, would certify these RECs.

Mr. Caister testified that the GPR pilot program achieves three objectives. First, the GPR pilot program provides an additional customer-focused option in its tariff that satisfies a customer expectation or desire that does not exist today. Second, the GPR pilot program supports Indiana's statewide goals to promote renewable and homegrown energy. Lastly, the GPR pilot program supports NIPSCO's mission to invest in clean, modern, and affordable energy solutions that support Indiana's long-term economic growth.

Mr. Caister explained that a customer can elect to participate in the program or cancel participation in the program by calling a NIPSCO customer service representative or through the customer's secure online account on NIPSCO's website. A customer seeking to enroll in the program will begin the program with the next billing cycle, and would see a separate "Green Power" line item on his or her bill. A customer seeking to withdraw from the program would remain on the GPR program through the then-current billing cycle in order to allow NIPSCO to account for RECs on a month-to-month basis. Participating residential and C&I customers have the option to designate 25%, 50%, or 100% of their total monthly electricity usage to be attributable to green power. C&I customers have the additional option to designate 5% or 10% of their total monthly electricity usage, because those customers have greater average usage levels than residential customers and a minimum election of 25% may prevent some of these customers from participating in the program. The 25% minimum for residential customers is based on a Green-e® requirement for the program's certification.

Mr. Caister testified that for the first six months of the program, NIPSCO proposes a GPR rate of \$0.002163/kWh. Therefore, for the first six months of the program, an average customer using 1,000 kWh per month who chooses the 100% option would pay an additional \$2.16 per month for green power. Mr. Caister explained how NIPSCO estimated the initial GPR rate. First, NIPSCO estimated the cost of the RECs (including all brokerage fees and trading commissions) and the incremental cost of marketing. NIPSCO then calculated the GPR rate by dividing the total costs by the estimated GPR sales in kWh and adjusting for Utility Receipts Tax. The costs and revenues would be subject to a true up in the next GPR filing via a reconciliation mechanism. At the time of Mr. Caiser's testimony, RECs for the Midwestern U.S. were trading at roughly $0.85 per megawatt-hour ("MWh") including brokerage fees. This price assumes a minimum purchase of 50,000 RECs, and the price has the potential to increase significantly with smaller purchases. NIPSCO projects to purchase less than 50,000 RECs for the first year of the program, so NIPSCO estimated $2.00 per REC.

To estimate sales, NIPSCO estimated that for each month of the first year of the program twenty-five new residential customers and two new C&I customers on average would enroll in the GPR. Because of the difficulty in estimating the level of usage each new customer would designate, NIPSCO used the average use per customer from IPL's 2010 Green Power Tariff Rider Annual Report. In future filings, NIPSCO would have a better understanding of average usage per customer in its own territory and would adjust the GPR accordingly.

Mr. Caister discussed how NIPSCO plans to keep the program economically attractive. Mr. Caister testified NIPSCO is working with the Center for Resource Solutions to obtain Green-e® certification for the GPR pilot program. The annual fee for Green-e® certification would be $10,125, and certification should take no longer than three months. Including a fixed annual fee of $10,125 to certify the program would increase the GPR costs to customers. Because a significant cost increase could potentially deter customers from participating in the program, NIPSCO has decided not to seek recovery for the certification costs at this time. As the program matures and more customers join the program, NIPSCO might seek to recover ongoing certification costs.

With respect to REC purchases, Mr. Caister said that initially, NIPSCO will purchase RECs as necessary to match participation levels and limit transaction costs. As participation grows, NIPSCO anticipates making semi-annual REC purchases. NIPSCO would acquire RECs at the lowest available cost. Purchasing all Indiana-sourced RECs could place upward pressure on the price of Indiana RECs, ultimately increasing the GPR cost and making the program unattractive to participating customers. However, in order for the GPR to be Green-e® certified, REC purchases must come from sources within the footprint of the Midwest Independent Transmission System Operator ("MISO"). Although purchasing RECs from within the MISO footprint is not a guarantee that the renewable energy will be generated in Indiana, it increases the possibility that the RECs would be attributable to green power generated in Indiana. Mr. Caister indicated that in-state only REC purchases might be something NIPSCO considers in the future, but at this time NIPSCO believes it should move forward as proposed. During the hearing, Mr. Caister clarified that, all other things being equal, NIPSCO could instruct brokers to select Indiana RECs over out-of-state RECs at the same price.

Mr. Caister also testified that NIPSCO would use a variety of low-cost marketing approaches to advertise the GPR program to customers, including utilizing NIPSCO's Internet website, bill inserts, and social media, among others. NIPSCO intends to use these types of approaches because they are low-cost methods that will allow the marketing expense to remain low in the initial stages of the program. NIPSCO will not initially seek recovery above the low semi-annual amount of $250 for advertising costs.

Mr. Caister stated that NIPSCO does not know the administrative costs for the program or the effect on employee workload. Therefore, NIPSCO is not seeking recovery of incremental administrative costs included in the GPR calculation. Similarly, although NIPSCO expects that costs resulting from the changes in the Customer Information System could occur, it is not seeking recovery of these costs through the GPR.

Next, Mr. Caister discussed the GPR filings. NIPSCO proposes to revise the GPR rate approximately six months after the effective date of the initial GPR and every six months thereafter. NIPSCO would calculate the revised rate using the same methodology and would provide for reconciliation of any over- or under-recovery of program costs during a prior period. NIPSCO proposes to file a petition requesting approval of the revised GPR rate in an expedited docketed proceeding under a subdocket in this Cause. NIPSCO believes that periodic updates would make the GPR program more responsive to price changes, thereby benefiting customers.

Mr. Caister testified the proposed pilot period would begin the date the Commission approves and stamps the tariff sheets proposed in this Cause. The pilot and Rider would continue through December 31, 2014. If NIPSCO believes the program should continue, it would submit a request by July 1, 2014, requesting approval for an extension or modification of the program.

Curt A. Westerhausen, Director of Rates and Contracts, sponsored proposed Rider 686 – Green Power Rider, Original Sheet No. 199.3 of NIPSCO's IURC Electric Service Tariff, Original Volume No. 12; necessary revisions to the Table of Contents, Second Revised Sheet No. 3; and Appendix A – Applicable Riders, Second Revised Sheet No. 201, of NIPSCO's IURC Electric Service Tariff, Original Volume No. 12.

Mr. Westerhausen also explained the billing aspects of the program. NIPSCO would continue to bill participants under their current applicable rate with a separate line item showing the premium to participate in the GPR. NIPSCO would calculate this premium by multiplying the GPR rate by the kilowatt-hours the customer specifies to be subject to the GPR.

Mr. Westerhausen testified that customers would not need to sign any contract to participate in NIPSCO's GPR program. If customers notify NIPSCO that they want to withdraw from the program the next billing cycle would reflect any withdrawal. All customer classes (Residential, Commercial, and Industrial) taking service under Rates 611, 612, 613, 620, 621, 622, 623, 624, 625, 626, 632, 633, 634, 641, 642, 644, 647, 650, 655, 660, and Rider 676 would be eligible to participate. NIPSCO plans to place no limit on customer purchases since REC purchases are administrative functions and do not impact the integrity of the electric distribution system.

Mr. Westerhausen testified the GPR program would be revenue neutral. NIPSCO intends for the GPR rate to cover all costs associated with the program, including the cost of RECs (which includes all brokerage fees and trading commissions), marketing, and all applicable taxes. He explained the costs and revenues would be subject to a "true up" in a subsequent GPR filing through a reconciliation mechanism.

Mr. Westerhausen testified the proposed GPR might result in greater expansion of electricity generated from Indiana-based wind, solar, and biomass facilities. NIPSCO has a current REC inventory from wind power purchase agreements and the total cost of generation under the power purchase agreements is currently recoverable through Fuel Adjustment Clause proceedings. The

GPR program would not alter this treatment and all RECs created from NIPSCO's wind purchases would be separate from the GPR program.

5. **OUCC's Evidence.** Cynthia M. Armstrong, a Senior Utility Analyst in the OUCC's Electric Division, testified that the OUCC generally supports NIPSCO's GPR program. Ms. Armstrong believes NIPSCO's forecasted cost of RECs at $2.00 per MWh is reasonable. Ms. Armstrong reviewed the most recent state REC market prices, and said that NIPSCO's purchases appear to be within the appropriate range of REC market prices. She also believes NIPSCO's estimate is within the range of other Midwestern utility green power rates.

Ms. Armstrong testified that the OUCC recognizes NIPSCO might incur additional annual administrative fees to maintain Green-e® certification for its GPR program. NIPSCO's program must undergo an annual certification audit in order for the program to remain Green-e® certified. Green-e® certification will add to NIPSCO's administrative costs for the GPR program, but the OUCC views this as a worthwhile expenditure. The certification process provides additional transparency and verification to GPR participants that NIPSCO has purchased RECs from suitable, local, renewable power producers.

Ms. Armstrong testified about the distinction between NIPSCO's GPR proposal and NIPSCO's current wind purchase power agreements. The RECs that NIPSCO receives from its wind purchase power agreements would not be included in the RECs purchased for the GPR program. Ms. Armstrong noted the importance of keeping those inventories separate in order to remain consistent with past Commission rulings regarding utility green power programs.

Ms. Armstrong testified the OUCC has two concerns about NIPSCO's proposed GPR pilot program. The OUCC's first concern involves the marketing and administrative budgets. $250 might not adequately allow NIPSCO to advertise the GPR program to its customers, resulting in standard service customers subsidizing the costs for GPR participants. The OUCC will evaluate NIPSCO's low-cost methods of marketing and administration during the first six months of the GPR program before making any recommendation to increase the GPR rate. The OUCC recommends that NIPSCO internally track the marketing and administrative resources the GPR program requires and report on these costs in subsequent GPR filings and annual reports. The OUCC is also concerned that the administration of the GPR program could affect the existing workload of employees serving all of NIPSCO's customers.

The OUCC's second concern involves tariff language for disconnection. NIPSCO's tariff contains no language preventing NIPSCO from disconnecting customers for failure to pay the GPR portion of their bills. NIPSCO would treat a GPR program participant that fails to pay for any part of standard service like any other past due customer. Ms. Armstrong understands that NIPSCO's current billing system is not programmed to differentiate the payment for the GPR premium and the rest of the bill and NIPSCO anticipates that these changes to its billing system would be cost-prohibitive for the GPR program. She also noted that the GPR portion of an average residential customer's bill would likely be small enough so that several months would pass before triggering the disconnection process. Based on this, the OUCC is not recommending that NIPSCO change its billing system to differentiate between the GPR premium and billing for standard service.

Mr. Armstrong testified that the OUCC recommends that NIPSCO file an annual report, detailing the performance and activities of the GPR program over the program's duration to provide useful information to the OUCC and the Commission in their ongoing review of the GPR program.

Ms. Armstrong testified the OUCC applauds NIPSCO's effort to offer a green power program to its customers. Ratepayers benefit from having access to the option to purchase renewable power at an affordable price. As a result, the OUCC recommends the Commission approve of NIPSCO's proposed GPR pilot program and NIPSCO's rate calculation of the initial factor at $0.002163/kWh.

6. **NIPSCO's Rebuttal Evidence.** Mr. Caister submitted rebuttal testimony addressing the comments and limited concerns expressed by Ms. Armstrong and said that Mr. Caister testified that NIPSCO agreed to file an annual report in this Cause as requested by the OUCC.

In response to the OUCC's first concern that NIPSCO's initial allotment for marketing costs may not adequately allow the NIPSCO to advertise to its customers, Mr. Caister testified that NIPSCO would utilize various low-cost and no-cost marketing approaches, which NIPSCO believes will effectively inform and alert customers about the GPR Program. NIPSCO prefers a conservative approach to the expenses included in the marketing budget. A lower budget would likely be the most effective in the initial stages of the program and NIPSCO wants to increase this budget only as needed. Any additional costs in the early stages of the program, when participation is low, might significantly increase the GPR premium to a level that customers may view unattractive.

Mr. Caister also responded to the OUCC's subsidy worry. NIPSCO understands the concern to the extent any subsidy would exist. However, NIPSCO believes changes caused by the GPR program's administration would not be material, and NIPSCO will monitor the costs and workloads to address this concern. NIPSCO will provide observations on this issue within the annual report. If administrative costs and workloads turn out to be greater than NIPSCO expected, it would reconsider recovery of these costs through the GPR subject to the same caution about increasing the GPR premium to an unattractive level.

Mr. Caister also addressed the OUCC's second concern regarding tariff language. Due to the particular billing protocols in NIPSCO's system, specific tariff language would be unnecessary. If a customer did not pay only that portion attributable to the GPR premium, many months would pass before a customer's account would reach the point where the disconnection process begins because NIPSCO does not initiate the disconnection process for a residential customer until the customer is delinquent by at least $75. NIPSCO designed its GPR Program for simple enrollment and withdrawal procedures. Customers can easily withdraw participation from the program by contacting NIPSCO directly through telephone or Internet.

7. **Commission Discussion and Findings.** Based on the evidence, the Commission finds that NIPSCO's GPR pilot program is designed to allow customers to voluntarily designate a percentage of their electricity usage to be green power. NIPSCO will purchase certified RECs in an amount equal that designated to be green power by its customers. Through the GPR rate, NIPSCO will pass the costs of the RECs, including brokerage fees and trading commissions, and minimal administrative and marketing costs to participating customers. Thus, the program allows

participating customers to support the development of clean energy resources but will have a minimal impact on non-participating customers.

In addition, NIPSCO proposed that the program be created on a pilot basis until December 31, 2014, and has agreed to file regular reports assessing the program. As a result, the Commission and the OUCC will have sufficient opportunity to further review the program and to work with NIPSCO to make any necessary modifications. Therefore, we approve NIPSCO's proposed GPR pilot program effective with the first billing cycle of the January 2013 billing month. We commend NIPSCO for initiating this pilot program that allows its customers to voluntarily support the use of renewable energy sources.

For the initial six-month period of the GPR pilot program, NIPSCO estimated a rate of \$0.002163/kWh to charge participants. The evidence shows that NIPSCO took reasonable measures to estimate the cost of RECs based on estimated purchases for the first six months. We also find that NIPSCO has taken reasonable steps to mitigate the early costs of the program by keeping initial marketing costs low and by excluding the costs of Green-e® certification for the program. Therefore, we approved NIPSCO's initial GPR rate of \$0.002163/kWh subject to reconciliation in the first GPR filing. However, we are concerned with the sufficiency of NIPSCO's marketing budget to properly inform customers about the GPR pilot program. We encourage NIPSCO to review the sufficiency of its marketing budget and to investigate additional marketing opportunities for the program prior to its first GPR adjustment filing.

Beginning six months after the effective date of this Order and every six months thereafter, NIPSCO proposes to submit a GPR adjustment filing. In each GPR adjustment, NIPSCO will reconcile the previous estimated GPR rate with actual costs and estimate a new GPR rate for the upcoming six months. NIPSCO's proposal is similar to our treatment of green power tariffs for other regulated utilities. Therefore, we approve NIPSCO's proposed reconciliation process and we authorize NIPSCO to amortize the amount of over- or under-collections associated with its GPR over a six-month period. NIPSCO shall file its first GPR adjustment filing under Cause No. 44198 GPR 1 six months after the effective date of this Order.

Finally, NIPSCO agreed to file an annual report under this Cause that will contain an assessment of administrative resources along with the following information:

- the number of customers enrolled in the Program per month, including a breakdown of residential and commercial and industrial ("C&I") customers by participation level;
- the suppliers of renewable energy certificates ("RECs") purchased for the Program;
- the quantity of the RECs purchased for the Program;
- the price and costs of RECs purchased for the Program;
- the administrative costs of the program by major category;
- the marketing costs by major category;
- a summary of Program activities, results, and observations; and
- a copy of any marketing materials sent to customers.

At the August 30, 2012 evidentiary hearing, in response to questions from the bench, Mr. Caister stated that NIPSCO would also include in the annual report a discussion of customer opinion or information regarding the availability of REC sources based in Indiana relative to other locations. We strongly encourage NIPSCO, when it is fiscally prudent, to purchase RECs from Indiana-based sources. In addition, NIPSCO shall include in its annual report the location of the source of each REC purchased through the pilot program. We believe this additional information will allow NIPSCO and the Commission to more fully understand the feasibility of purchasing RECs sourced in the state.

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

1. NIPSCO's Rider 686 – Green Power Rider (Original Sheet No. 199.3 of its IURC Electric Service Tariff, Original Volume No. 12) is approved for a pilot period ending December 31, 2014, to become effective upon its filing with the Electricity Division of the Commission.

2. NIPSCO's requested Green Power Rider rate as set forth at Finding Paragraph No. 7 is approved to be effective with the first billing cycle of the January 2013 billing month. The Green Power Rider rate approved herein, upon becoming effective, shall remain in effect until a new revised rate is approved.

3. Within six months after the effective date of this Order, NIPSCO shall file its first Green Power Rider rate adjustment proceeding with the Commission under Cause No. 44198 GPR 1. NIPSCO is authorized to include a reconciliation mechanism to ensure that any over- or under-recovery of program costs will be reflected in each revised rate and to collect any gross receipts or revenue-related tax occasioned by such Green Power Rider revenues.

4. NIPSCO shall file in this Cause a status report stating its intent to continue the Green Power Rider, modify the Green Power Rider, or terminate the Green Power Rider on or before July 1, 2014.

5. NIPSCO shall file in this Cause an annual report containing an assessment of administrative resources along with the additional information discussed in Paragraph No. 7 above on January 31, 2014, covering calendar year January to December 2013 and on January 31, 2015, covering calendar year January to December 2014.

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

ATTERHOLT, BENNETT, LANDIS, MAYS AND ZIEGNER CONCUR:

APPROVED: DEC 19 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

ORIGINAL

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY FOR (1) APPROVAL OF AND A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR QUALIFIED POLLUTION CONTROL PROPERTY, CLEAN COAL TECHNOLOGY, CLEAN ENERGY PROJECTS AND FEDERALLY MANDATED COMPLIANCE PROJECTS NECESSARY TO ALLOW PETITIONER TO COMPLY WITH THE MATS RULE; (2) APPROVAL OF PROPOSED COST ESTIMATES FOR MATS COMPLIANCE PLAN PROJECTS; (3) APPROVAL OF SPECIFIC RATEMAKING AND ACCOUNTING TREATMENT; (4) APPROVAL TO DEPRECIATE THE PROJECTS ACCORDING TO THE DEPRECIATION RATES APPROVED IN CAUSE NO. 43969; (5) APPROVAL OF ONGOING REVIEW OF THE MATS COMPLIANCE PLAN PROJECTS AS PART OF PETITIONER'S SEMI-ANNUAL PROGRESS REPORTS FILED IN CAUSE NO. 42150-ECR-XX; AND (6) AUTHORITY TO PERFORM DISPATCH OF ITS GENERATION UNITS IN A MANNER NECESSARY TO COMPLY WITH THE REQUIREMENTS OF THE MATS RULE; ALL PURSUANT TO IND. CODE §§ 8-1-2-6.8, 8-1-8.8-1 *ET SEQ.*, 8-1-8.7-1 *ET SEQ.*, 8-1-8.4 *ET SEQ.* AND 170 IAC 4-6-1 *ET SEQ.*;	)	CAUSE NO. 44311 APPROVED: OCT 10 2013

ORDER OF THE COMMISSION

Presiding Officers:
Kari A.E. Bennett, Commissioner
Aaron A. Schmoll, Senior Administrative Law Judge

On February 22, 2013, Northern Indiana Public Service Company ("Petitioner," "NIPSCO" or "Company") filed its Verified Petition in this Cause. On February 22, 2013, NIPSCO also filed its Case-In-Chief and a Motion for Protection and Nondisclosure of Confidential and Proprietary Information. On March 15, 2013, the NIPSCO Industrial Group ("Industrial Group") and on March 20, 2013, the Citizens Action Coalition of Indiana, Inc. ("CAC") filed petitions to intervene, both of which were subsequently granted. On March 21, 2013 CAC filed a Motion for Field Hearing, which was granted by Docket Entry on April 11, 2013. A public field hearing was held on April 22, 2013 at the Lake County Government Center Auditorium in Crown Point, Indiana.

On May 7, 2013, the Indiana Office of Utility Consumer Counselor ("OUCC") prefiled direct testimony and consumer comments and the Industrial Group prefiled direct testimony. NIPSCO prefiled rebuttal testimony on May 23, 2013.

Pursuant to notice given as provided by law, proof of which was incorporated into the record, an evidentiary hearing was held in this matter on June 3, 2013, at 9:30 a.m., in Room 222, PNC Center, 101 West Washington Street, Indianapolis, Indiana. At the hearing, the prefiled evidence of NIPSCO, OUCC and Industrial Group were admitted into the record without objection. CAC did not file testimony in this Cause. No members of the general public appeared or participated at the hearing.

Having considered the evidence and being duly advised, the Commission now finds:

1. **Notice and Jurisdiction.** Due, legal and timely notice of the hearing in this Cause was given as required by law. Petitioner is a "public utility" within the meaning of Ind. Code § 8-1-2-1 and Ind. Code § 8-1-8.7-2, a "utility" within the meaning of Ind. Code § 8-1-2-6.8 and 170 IAC 4-6-1, an "energy utility" within the meaning of Ind. Code §§ 8-1-2.5-2 and 8-1-8.4-3, and an "eligible business" within the meaning of Ind. Code § 8-1-8.8-6. Pursuant to Indiana Code ch. 8-1-8.4, the Commission has authority to issue a Certificate of Public Convenience and Necessity ("CPCN") for federally-mandated projects. Pursuant to Indiana Code ch. 8-1-8.8, the Commission has authority to approve clean energy projects for certain incentives. Accordingly, the Commission has jurisdiction over Petitioner and the subject matter of this proceeding.

2. **Petitioner's Characteristics and Generating System.** Petitioner is a public utility organized and existing under the laws of the State of Indiana and having its principal office at 801 East 86th Avenue, Merrillville, Indiana. Petitioner is engaged in rendering electric and gas 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 generation, transmission, distribution and furnishing of such service to the public. The NIPSCO generation resources include 3,322 megawatts ("MWs") of coal, natural gas and hydroelectric generation as well as 100 MW of wind-generated purchases. Petitioner's demand-side resources include energy efficiency, energy conservation and demand response programs which help to reduce customers' electricity consumption, or shift consumption from peak hours to off-peak hours. In 2012, Petitioner's net generation by fuel consisted of 56% coal, 18% gas, and 26% a combination of wind, hydro and purchases from the Midcontinent Independent System Operator, Inc. ("MISO"). Petitioner's coal generation facilities include seven (7) units at three (3) separate sites and include R.M. Schahfer Generating Station ("Schahfer"), Michigan City Generating Station ("Michigan City") and Bailly Generating Station ("Bailly").

3. **Background and Requested Relief.** Petitioner's operations are subject to federal, state and local rules promulgated by, among others, the United States Environmental Protection Agency ("EPA") and the Indiana Department of Environmental Management ("IDEM"). Such rules establish environmental compliance standards that govern emissions from Petitioner's electric generating units.

On December 16, 2011, in accordance with section 112 of the Clean Air Act ("CAA"), the EPA signed a rule to reduce mercury, other non-mercury metals, and acid gas emissions from coal- and oil-fired power plants. Specifically, these standards established direct and surrogate emission standards based upon Maximum Achievable Control Technology ("MACT") (referred to by the EPA as its Mercury and Air Toxics Standards or "MATS" rule) to address hazardous air pollutant emissions ("HAPs") from new and existing coal- and oil-fired electric utility steam generating units. Compliance for Petitioner's affected units will be required within three years after the effective date of the rule or April 16, 2015, with the possibility of an additional one year extension based upon a demonstration that additional time is needed in order to install control technology.

The MATS rule establishes new emission limits for Petitioner's coal-fired generators. In order to comply with the MATS rule, Petitioner has developed its MATS Compliance Plan. Petitioner's MATS Compliance Plan includes three types of capital projects: Activated Carbon Injection ("ACI") and Fuel Additives to reduce mercury emissions and Transformer Rectifier Sets ("TR Sets") to reduce particulate matter ("PM") emissions (together, the "MATS Capital Projects") and several incremental operating and maintenance ("O&M") projects ("O&M Projects") necessary to reduce emissions of mercury and PM to levels required by the MATS rule (collectively referred to as "MATS Compliance Plan Projects"). The MATS Capital Projects include the following: Unit 7 ACI (mercury reduction), Unit 7 Fuel Additives (mercury reduction), Unit 8 ACI (mercury reduction), Unit 8 Fuel Additives (mercury reduction), Unit 12 ACI (mercury reduction), Unit 12 Fuel Additives (mercury reduction), Unit 14 ACI (mercury reduction), Unit 14 Fuel Additives (mercury reduction), Unit 14 TR Sets (PM reduction), Unit 15 ACI (mercury reduction), Unit 15 Fuel Additives (mercury reduction), Unit 15 TR Sets (PM reduction), Unit 17 TR Sets (PM reduction), and Unit 18 TR Sets (PM reduction). The O&M Projects include the following: Precipitator and FGD Mist Eliminator Cleaning on Units 7 and 8, Unit 15 ESP Flow Modeling, and Schahfer Air and Water Testing (Units 14, 15, 17 and 18).

By its Petition, Petitioner requests the following relief on or before September 30, 2013:

(a) granting Petitioner a certificate of public convenience and necessity ("CPCN") for the MATS Compliance Plan Projects pursuant to Ind. Code § 8-1-8.8-1 *et seq.*, Ind. Code § 8-1-8.7-1 *et seq.*, and Ind. Code § 8-1-8.4 *et seq.*;

(b) approving the proposed cost estimates for the MATS Compliance Plan Projects;

(c) finding that the MATS Capital Projects constitute "qualified pollution control property" and "clean coal technology" and are eligible for the ratemaking treatment described in Ind. Code § 8-1-2-6.8, Ind. Code § 8-1-8.7-1 *et seq.*, and 170 IAC 4-6-1 *et seq.*;

(d) finding that the MATS Capital Projects constitute "clean energy projects" under Ind. Code § 8-1-8.8-1 *et seq.*, and finding that the projects are reasonable and necessary and therefore eligible for the financial incentives set forth in Ind. Code § 8-1-8.8-11;

(e) finding that the MATS Compliance Plan Projects constitute "federally mandated compliance projects," that the costs incurred in connection with the MATS Compliance Plan Projects are "federally mandated costs" under Ind. Code § 8-1-8.4-1 *et seq.*, and that the MATS Compliance Plan Projects are eligible for the ratemaking treatment described in Ind. Code § 8-1-8.4-7;

(f) authorizing Petitioner to utilize construction work in progress ("CWIP") ratemaking treatment for qualified pollution control property and clean energy projects consistent with and through Petitioner's currently-effective Rider 672 – Adjustment of Charges for Environmental Cost Recovery Mechanism ("ECRM") tracking mechanism;

(g) finding that the MATS Capital Projects are deemed to be under construction until such time the Commission determines that they are used and useful in a proceeding that involves the establishment of new electric basic rates and charges for Petitioner;

(h) authorizing Petitioner to accrue allowance for funds used during construction ("AFUDC") relating to the MATS Capital Projects;

(i) authorizing Petitioner to depreciate the MATS Capital Projects according to depreciation rates approved in the Commission's December 21, 2011 Order in Cause No. 43969 ("43969 Order");

(j) authorizing the timely recovery of reasonably incurred O&M expenses and depreciation expenses relating to the MATS Capital Projects consistent with and through Petitioner's currently-effective Rider 673 – Adjustment of Charges for Environmental Expense Recovery Mechanism ("EERM") tracking mechanism pursuant to Ind. Code § 8-1-8.8-11;

(k) authorizing Petitioner to recover 80% of the federally mandated costs incurred in connection with the O&M Projects through Petitioner's currently-effective EERM tracking mechanism pursuant to Ind. Code § 8-1-8.4-7;

(l) authorizing Petitioner to defer depreciation and O&M expenses relating to the MATS Compliance Plan Projects until such expenses are recovered through Petitioner's currently-effective EERM tracking mechanism;

(m) authorizing Petitioner to defer 20% of the federally mandated costs incurred in connection with the O&M Projects for recovery in Petitioner's next general rate case pursuant to Ind. Code § 8-1-8.4-7;

(n) authorizing Petitioner to recover pre-construction costs incurred prior to and after approval of a Final Order in this proceeding to the extent that such costs are reasonable and consistent with the scope of the projects described in Petitioner's evidence through Petitioner's currently-effective ECRM tracking mechanism;

(o) providing for ongoing review of the MATS Compliance Plan Projects as part of Petitioner's semi-annual progress reports filed in Cause No. 42150-ECR-XX; and

(p) authorizing Petitioner to perform dispatch of its generation units in a manner necessary to comply with the requirements of the MATS rule and declaring such procedures to be in compliance with current and future dispatch parameters relating to the recovery of fuel costs.

4. **Summary of Evidence.**

A. **Petitioner's Direct Testimony.**

i. **Direct Testimony of Timothy R. Caister.** Timothy R. Caister, Director of Regulatory Policy for NIPSCO, testified that NIPSCO designed a portfolio of projects (the "MATS Compliance Plan") in order to comply with the MATS rule. Mr. Caister stated that

NIPSCO was seeking: (1) approval of and a CPCN for qualified pollution control property ("QPCP"), clean coal technology, clean energy projects, and federal mandated compliance projects necessary to allow NIPSCO to comply with the MATS rule pursuant to Ind. Code §§ 8-1-2-6.8, 8-1-8.8-1 *et seq.*, 8-1-8.7-1 *et seq.*, and 8-1-8.4-1 *et seq.*; (2) approval of the proposed cost estimates for the MATS Compliance Plan Projects; (3) approval of specific ratemaking and accounting treatment; (4) approval to depreciate the projects according to the depreciation rates approved in the 43969 Order; (5) approval of ongoing review of the MATS Compliance Plan Projects as part of NIPSCO's semi-annual progress reports filed in Cause No. 42150-ECR-X; and (6) authority to perform dispatch of its generation units in a manner necessary to comply with the requirements of the MATS rule.

ii. <u>Direct Testimony of Kelly R. Carmichael</u>. Kelly R. Carmichael, Director of Environmental Policy and Permitting for NIPSCO, testified that the MATS rule established numerical standards for existing coal-fired electric generation units including emission limits for: Mercury ("Hg"), Total PM (surrogate for non-Hg metals), and sulfur dioxide ("SO_2") or Hydrogen Chloride ("HCl") surrogates for acid-gas HAPs. Mr. Carmichael stated that the legal challenges to the MATS rule may not be resolved until 2014. He stated that despite the pendency of litigation, the MATS compliance deadline is, and remains, April 16, 2015, and NIPSCO will proceed with its current compliance plan. He stated that NIPSCO submitted a letter to IDEM on January 30, 2013, requesting a one year extension for meeting the emission standards for (1) Michigan City Unit 12 related to SO_2, Hg and PM, (2) Schahfer Unit 14 related to Hg, and (3) Schahfer Unit 15 related to Hg, which he expected would be approved.

Mr. Carmichael testified that numerous recent and pending air, water and solid waste regulations have the potential to affect NIPSCO's electric generation units: (1) Clean Air Interstate Rule ("CAIR"), the nitrogen oxide ("NO_x") and SO_2 emission allowance trading program; (2) tighter National Ambient Air Quality Standards ("NAAQS"); (3) Greenhouse Gas emission thresholds; (4) EPA's proposed Phase II Rule of the Clean Water Act Section 316(b); (5) impending Effluent Limitation Guidelines; and (6) EPA's proposed rule for regulation of Coal Combustion Residuals. NIPSCO has included the long-term compliance implications – and costs – of each of these into its planning process.

Mr. Carmichael testified relating to the process through which NIPSCO determined that its coal units do not currently comply with the MATS rule and how its MATS Compliance Plan will help it comply with the rule – including a discussion about the relationship between ACI and Fuel Additives. He testified that the Company's MATS Compliance Plan is reasonable, appropriate and in the public interest because it is a cost effective approach to achieving compliance with the emission standards set forth in the MATS rule.

iii. <u>Direct Testimony of Michael Hooper</u>. Michael Hooper, Vice President of Major Projects for NIPSCO, testified that the MATS Compliance Plan is necessary to reduce emissions of mercury and PM to levels required by the MATS rule. He stated the total estimated capital costs associated with NIPSCO's MATS Compliance Plan is $59.28 million.

Mr. Hooper testified that to develop the MATS Compliance Plan, various departments within NIPSCO reviewed historical emissions data to evaluate which units have potential compliance risk. NIPSCO then commissioned an engineering study by Sargent & Lundy, LLC ("S&L") to assess each unit relative to the emissions data as well as the physical characteristics and condition of each unit (the "S&L Report"). Mr. Hooper testified that the Company also reviewed the current configuration and condition of its facilities and other physical attributes. NIPSCO then reviewed engineering recommendations contained in the S&L Report and, through an iterative process, developed a proposed project portfolio for each unit. He stated that the proposed project portfolio is supported by both the engineering study results and the emissions test data. Mr. Hooper indicated that the implementation schedule is guided by the April 16, 2015 effective date of the MATS rule but that since the Company has requested from IDEM an extension of the deadline for Units 12, 14 and 15, the compliance date for those units would be April 16, 2016.

Mr. Hooper testified that the MATS Compliance Plan Projects constitute QPCP, clean energy projects, and are federally-mandated. He stated the projects all consist of air pollution control devices that will be used on a coal burning energy generating facility and that they directly or indirectly reduce airborne emissions of mercury or other regulated air emissions associated with the combustion or use of coal. Mr. Hooper testified each of these projects will reduce emissions of pollutants including mercury and PM from NIPSCO's generating plants. He stated NIPSCO will obtain all required permits to install these projects and they will meet applicable state or federal requirements. As a result, each capital project included in the MATS Compliance Plan constitutes both QPCP and clean coal technology under Ind. Code § 8-1-2-6.8, and a clean energy project under Ind. Code § 8-1-8.8-2(B). He testified that because MATS is a requirement imposed by the EPA, it is a federally mandated requirement under Ind. Code § 8-1-8.4-5(7). Mr. Hooper testified that because NIPSCO's MATS Compliance Plan is related to the direct compliance by NIPSCO with the EPA's MATS rule, the MATS Compliance Plan is a compliance project under Ind. Code § 8-1-8.4-2 and the costs NIPSCO will incur in connection with the MATS Compliance Plan are federally-mandated costs under Ind. Code § 8-1-8.4-4.

iv. <u>Direct Testimony of Cecelia Largura</u>. Cecelia Largura, Director of Strategic Execution for NIPSCO, testified regarding the process NIPSCO used to evaluate various options for compliance with the MATS rule. She stated that for each unit, both the MATS Compliance Plan as well as the options presented in the S&L Report were evaluated to determine whether the decision to invest in various compliance equipment options was preferred over unit retirement. She testified the option to replace each coal unit's generation with market alternatives was also evaluated.

Ms. Largura described the Strategist® model, which was used to evaluate the options described above, based on a twenty-year planning horizon. She stated the options were ranked based on net present value revenue requirement ("NPVRR"). She testified that NIPSCO identified potential changes in assumptions that could impact the decision, and conducted that sensitivity and scenario analysis with different input assumptions, as well as breakpoint analysis, to evaluate the impact on the MATS Compliance Plan decision.

Ms. Largura testified that the results of the analysis demonstrated that NIPSCO's MATS Compliance Plan is the preferred option to meet the future resource needs of its customers. She stated that the MATS Compliance Plan carries the lowest NPVRR and appropriately mitigates risk.

v. <u>Direct Testimony of Angela P. Camp</u>. Angela P. Camp, Manager of Financial Reporting for NIPSCO, testified regarding NIPSCO's requested accounting treatment for the MATS Capital Projects and O&M Projects. She testified that NIPSCO proposes to continue recording AFUDC associated with QPCP and clean energy project costs, in accordance with

Generally Accepted Accounting Principles, until such costs are given CWIP ratemaking treatment or are otherwise reflected in NIPSCO's base electric rates or the MATS Compliance Plan Projects are placed in service, whichever occurs first.

Ms. Camp testified that for O&M expenses associated with the QPCP and clean energy projects, NIPSCO is proposing that associated depreciation and O&M expenses be deferred until such expenses receive ratemaking treatment or are otherwise reflected in NIPSCO's base electric rates. She stated the Company will certify its expenses to the Commission and request approval to recover actual depreciation and O&M expenses once the MATS Compliance Plan Projects are placed in service on an annual basis, consistent with past practice using the EERM. Ms. Camp testified that the ACI and Fuel Additives and the TR Sets will be depreciated based on the depreciation rates that were approved in the 43969 Order.

Ms. Camp testified that pursuant to Ind. Code § 8-1-8.4-7, NIPSCO proposes to recover 80% of the actual O&M expenses associated with the O&M Projects through NIPSCO's EERM. She stated that NIPSCO proposes to defer 20% of the actual O&M expenses associated with the O&M Projects, as a regulatory asset for recovery as part of NIPSCO's next general rate case.

vi. Direct Testimony of Derric J. Isensee. Derric J. Isensee, Manager of Regulatory Support and Analysis for NIPSCO, testified that NIPSCO proposes to seek ratemaking treatment for its MATS Compliance Plan Projects through its currently-effective ECRM and EERM tracker mechanisms. He stated that NIPSCO seeks authority to (a) implement CWIP ratemaking treatment for the MATS Compliance Plan Projects capital costs through the ECRM and (b) record an AFUDC on the MATS Compliance Plan Projects' construction costs until the costs receive either CWIP ratemaking treatment through the ECRM, are placed in service or are otherwise reflected in base electric rates. Mr. Isensee stated that the Company requests timely recovery, through the EERM, of reasonably incurred O&M and depreciation expenses associated with each approved project beginning when it is placed in service. With respect to the QPCP and clean energy projects within NIPSCO's MATS Compliance Plan, Mr. Isensee testified that NIPSCO is proposing to include all (1) capital expenditures in the semi-annual ECRM filings, and (2) pursuant to Ind. Code § 8-1-8.8-11, depreciation and O&M expenses in the annual EERM filings.

Mr. Isensee testified that rather than creating a new tracking mechanism, NIPSCO is proposing to include 80% of all O&M expenses related to the O&M Projects in the annual EERM filings in order to recover such project expenses in a timely manner. He stated that these expenses would be treated consistently with O&M expenses recovered as part of NIPSCO's other environmental compliance plans (NOx Compliance Plan, CAIR/CAMR Compliance Plan and Multi-Pollutant Compliance Plan).

B. OUCC's Direct Testimony.

i. Direct Testimony of Edward T. Rutter. Edward T. Rutter, Utility Analyst, testified that the MATS Compliance Plan is consistent with NIPSCO's 2011 Integrated Resource Plan ("IRP"). Mr. Rutter testified concerning the possible risks associated with continued retrofits to existing coal generating facilities relative to retirement and/or replacement and concluded that the latter alternatives will not replace existing generation or may have attendant risks or problems that may nullify or minimize any perceived advantages. Mr. Rutter testified that, in his opinion, the MATS Compliance Plan was based on reasonable assumptions of costs and circumstances for each of the alternatives tested based on what is known today.

ii. Direct Testimony of Cynthia M. Armstrong. Cynthia M. Armstrong, Senior Utility Analyst in the Electric Division, testified concerning all of the regulations, in addition to the MATS rule, that are driving the need for the MATS Compliance Plan, and described the impact of proposed environmental regulations. Ms. Armstrong focused on MATS, Cross State Air Pollution Rule ("CSAPR"), CAIR, and the fine PM NAAQS, as she testified they have the most impact on NIPSCO's proposed environmental projects. She testified that many of NIPSCO's units are non-compliant with both current mercury limits and the MATS Hydrochloric Acid ("HCI") standard.

Ms. Armstrong testified that there is a need for NIPSCO's requested Schahfer TR Sets as well as the ACI Systems on Bailly Units 7 and 8, Michigan City Unit 12 and Schahfer Units 14 and 15 and therefore the OUCC recommends the issuance of a CPCN for these items. However, she stated that the Fuel Additives systems are not necessary and testified that NIPSCO may have overstated the units' AC injection rate in its Fuel Additives system economic analysis, which would then alter the cost effectiveness of installing and testing the Fuel Additives systems. Thus, the OUCC recommended the denial of a CPCN for Fuel Additives systems on Bailly Units 7 and 8, Michigan City Unit 12 and Schahfer Units 14 and 15. She testified that if after testing the ACI systems on these units, NIPSCO finds that the AC injection rate is high enough to warrant testing the Fuel Additives system, NIPSCO can re-apply for a CPCN for the Fuel Additives systems at that time. She stated that NIPSCO should report the results of the ACI tests on its units to the Commission, the OUCC, and any other interested consumer parties.

iii. Direct Testimony of Anthony A. Alvarez. Anthony A. Alvarez, Utility Analyst in the Resource Planning and Communications Division, testified concerning Bailly, including air pollution control devices in use as well as a discussion of the Bailly MATS Compliance Plan Projects. Mr. Alvarez recommended the approval of the ACI Project and its $11,899,320 cost for Bailly. He recommended the denial of the proposed Fuel Additives projects for Bailly Units 7 and 8. He testified concerning the possibility that fuel additives can increase the corrosion risk in some areas of the boiler and flue gas path, and have the potential to present wastewater discharge complications, as well as the lack of certainty in the AC injection rate which is critical in determining economic feasibility. Mr. Alvarez also stated that NIPSCO should provide updated information regarding the (1) residence time of the AC on Bailly Unit 7 electrostatic precipitator ("ESP"); (2) AC injection rates to achieve compliance for Bailly Units 7 and 8; (3) economic feasibility analysis of the Fuel Additives system after determining the AC injection rates; (4) status of the "own-and-operate" commercial arrangement for the Bailly wet flue gas desulphurization ("FGD"); (5) operating status and condition of the wet FGD bypass smokestack; and (6) corrosion mitigation and control plan for Bailly Unit 8 ESP high voltage compartment decks.

iv. Direct Testimony of Ray L. Snyder. Ray L. Snyder, Utility Analyst in the Resource Planning and Communications Division, testified concerning Schahfer, including air pollution control devices presently in operation or approved for construction. He compared the S&L Report to the MATS Compliance Plan and testified that the capital cost of executing S&L's recommendations would be $174,176,600 more than what would be implemented in the MATS Compliance Plan. Mr. Snyder testified that the OUCC recommended that the Commission approve of the MATS Compliance Plan Projects at Schahfer, with the exception of the Fuel Additives projects. He stated the OUCC believes that the potential environmental risk and uncertainty of financial justification for those projects is too great. He testified that as NIPSCO gains experience with ACI additions and the amount of chemical consumed, the OUCC recommends NIPSCO re-evaluate the benefit/cost ratio of Fuel Additives systems and consider installation of Fuel Additives projects based on those results.

v. **<u>Direct Testimony of Maclean O. Eke</u>.** Maclean O. Eke, Utility Analyst in the Resource Planning and Communication Division, testified concerning Michigan City. He stated that NIPSCO will employ halogen-based fuel additives in conjunction with future dry FGD to first oxidize additional mercury present in the flue gas and then capture it in the FGD and particulate collection devices. Mr. Eke testified that final mercury emission trimming to meet compliance levels will be achieved by the ACI located upstream of the baghouse. He stated that NIPSCO's studies have not yet progressed to the point of a project schedule and scope and that NIPSCO currently does not have a contracting strategy.

Mr. Eke testified that the OUCC recommends the Commission approve installation of an ACI system for the Michigan City MATS Compliance Plan Projects. He stated that the OUCC recommends that the Commission deny NIPSCO's request to use Fuel Additives at Michigan City because using the baghouse/fabric filters approved in Cause No. 44012 as air pollution control equipment for Michigan City can achieve compliance without Fuel Additives.

vi. **<u>Direct Testimony of Wes R. Blakley</u>.** Wes R. Blakley, Senior Utility Analyst, testified regarding the OUCC's recommendations concerning NIPSCO's requested ratemaking treatment for its proposed MATS Compliance Plan Projects. He testified concerning the OUCC's disapproval of NIPSCO's effort to seek cost recovery for its MATS Compliance Plan Projects through three different statutes and testified that he does not believe the legislature intended for a utility to be able to cherry pick which statutory scheme it wanted to apply. He stated that should the Commission approve NIPSCO's request for a CPCN, the OUCC recommends that the cost recovery for all of NIPSCO's MATS Compliance Plan Projects be provided for under Ind. Code § 8-1-8.4 since the MATS Compliance Plan Projects are all federally mandated.

C. <u>Industrial Group's Direct Testimony</u>.

i. **<u>Direct Testimony of Nicholas Phillips, Jr</u>.** Nicholas Phillips, Jr., a Managing Principal of Brubaker & Associates, Inc., testified regarding the allocation of fixed MATS compliance costs in this proceeding and the need to treat those costs separately from the current pollution control costs being recovered in NIPSCO's existing ECRM and EERM trackers.

Mr. Phillips testified that NIPSCO had allocated QPCP fixed costs to classes on the basis of firm load (deducting interruptible load) of the four summer coincident peaks ("4 CP") method for many years, but that method was changed to the 12 coincident peak method ("12 CP") without subtracting interruptible load in Cause No. 42150 ECR 19 ("ECR 19"). Mr. Phillips stated that because: (1) the current approved base rates for NIPSCO are not a result of the 12 CP method; (2) the rates the Commission approved in Cause No. 43969 were not based on an approved cost of service study; (3) the flaws in NIPSCO's cost of service study in Cause No. 43969; and (4) the outdated and changed data upon which the Commission approved the 12 CP methodology in Cause

No. 43526, the most reasonable allocation for the new MATS Compliance Plan costs is to use the revenue allocation approved in NIPSCO's last base rate case, Cause No. 43969.

Mr. Phillips testified that although NIPSCO prepared and filed a cost of service study as part of its original filing in Cause No. 43969, it did not advocate rates based on the study, and the rates the Commission approved were not based on any cost of service study. Mr. Phillips stated that the Commission's Order in Cause No. 43969 discussed the difficulty in determining NIPSCO's true cost of service for each rate class because of a number of factors that existed during the test year.

Mr. Phillips stated that in Cause No. 43969, NIPSCO proposed an entirely new industrial rate structure. The information required to perform a cost of service study contained various uncertainties associated with customer operations during a severe recession and from customers operating on rate schedules that were being eliminated or contracts that had or would expire between the test year and implementation of new rates. Mr. Phillips noted that load data at the time of one-hour monthly system peaks during the test year may have been based on abnormal data due to the severe economic downturn. He said another problem was that customers on non-firm rates or a special contract during the test year were migrated to a firm rate under NIPSCO's proposed rate structure, making it difficult to estimate or assume exactly how a customer being migrated from a non-firm rate or special contract would operate under a different rate schedule with different price signals. He stated NIPSCO had to make various assumptions in migrating special contract customers' loads during the test year to existing rates and then had to make additional assumptions in migrating those customers' loads that were on non-firm rates, or customers who would have migrated to the non-firm rates, to firm rates. He testified these various factors created obstacles for any cost of service study in the rate case and these obstacles are reflected in the 12 CP allocators approved in ECR-19.

Mr. Phillips testified the Settling Parties recognized that load data, class migrations, revised pricing structures and the severe recession had a significant impact on normal usage characteristics and, therefore, any cost allocation study would be suspect. Consequently, the Settling Parties used an across-the-board approach to allocate the base rate revenue requirement (cost responsibility) to customer classes with mitigation of the increase to the residential class to arrive at a reasonable allocation of the revenue requirement to the customer classes. He added that as with a cost of service study, the agreed upon revenue responsibility by class in Cause No. 43969 established the allocation parameters upon which to allocate NIPSCO's revenue requirement among the customer classes. The resulting cost responsibility of the customer classes is reflected on Mr. Phillips NP-1. He stated that the Commission found that the revenue allocation constituted just and reasonable rates.

Mr. Phillips testified that he recommended the base rate revenue requirement allocation approved in Cause No. 43969 be used to allocate the fixed MATS costs to classes. Mr. Phillips based this recommendation on the fact that the revenue requirement allocation reflects the manner in which the Settling Parties agreed that cost responsibility is shared among the customer classes for base rates; no agreement on a cost of service method was achieved, or approved, in Cause No. 43969 because of the problems involving load data, rate migrations, and interruptible load transfers to firm service. He added that because no cost of service method was approved and allocation factors based on unreliable loads would be unreasonable, the agreed upon and Commission approved allocation of base rate revenue requirement by class is the superior, reasonable and most appropriate method for allocating the fixed MATS costs in this cause.

Mr. Phillips also explained the underlying problems with using the 12 CP methodology based on the Commission's findings in Cause No. 43526. He testified that the load data in Cause No. 43526 upon which the Commission adopted the 12 CP methodology was from a 2007 test year, prior to what might be the worst economic recession since the great depression. He noted that the loads, jobs and manufacturing activity may never return to the 2007 level. He said that basing a current finding on how new environmental project costs should be allocated on a methodology that relied upon 2007 data is unreasonable in his view.

Mr. Phillips added that the data, rate migrations and assumptions regarding customer loads in Cause No. 43526 made the resulting rates unworkable and they were never implemented. He noted the rates resulting from the 12 CP allocation methodology were based on the 2007 cost of service, loads, billing determinants and data that was fraught with difficulties. Mr. Phillips concluded that the 2007 data, which supported the Commission's findings that a 12 CP methodology was appropriate in Cause No. 43526, should not be used as the cornerstone of approving a methodology to allocate MATS costs to customer classes in this case.

Mr. Phillips testified the 12 CP factors from NIPSCO's cost study in Cause No. 43969 suffers from the same problems and therefore no valid reason exists to use NIPSCO's 12 CP allocation factors to allocate MATS costs to customers in this proceeding. He added that as utilities use trackers more and more and have rate cases less frequently, proper allocation methodologies are essential to providing just and reasonable rates and sending accurate signals to ratepayers.

Mr. Phillips testified that one way to address the need to use the allocation parameters in Cause No. 43969 for recovery of the MATS firm costs is to establish a new rider for recovery of the MATS Compliance costs. He said another possibility is NIPSCO could continue to use the existing ECRM and EERM Riders and prepare a separate schedule for the allocation of the MATS project costs, allocating the fixed costs pursuant to the base rate revenue requirement and allocating the variable costs on energy. He explained the separately allocated MATS costs could then be recovered as part of the ECRM and EERM riders.

Mr. Phillips also addressed the impact on the residential class of the allocation of base rate revenue requirement to customer class versus the 12 CP methodology of allocating fixed MATS costs to classes. Mr. Phillips testified the 12 CP method allocates 27.03% of fixed QPCP costs to the residential class, whereas the allocation of base rate revenue requirement method approved by the Commission in Cause No. 43969 allocates 27.882% to the residential class, which is very close to the same percentage. He said on that basis, there is no adverse impact to the residential class from the use of the approved allocation of base rate revenue requirement to class.

He added that under the base rate revenue allocation in Cause No. 43969, all classes received less than or approximately the system average increase other than the large industrial classes. Mr. Phillips testified the base rate revenue allocation resulted in the residential class receiving only a 4.788% increase in base rates, whereas the large industrial classes received over an 18% rate increase in Cause No. 43969. Mr. Phillips concluded that using the revenue requirement allocation parameters from NIPSCO's last rate case provides some rate relief to the largest employers in NIPSCO's service territory while having minimal impact on the residential class.

ii. **Direct Testimony of James R. Dauphinais.** James R. Dauphinais, Managing Principal of Brubaker & Associates, Inc., testified that he recommended that any CPCN granted for NIPSCO's MATS Compliance Plan Projects be conditioned on the following: (1) the Commission at this time only approve capital expenditure amounts no greater than those identified by NIPSCO in Petitioner's Exhibit No. MH-1; (2) the Commission should note that to the extent the actual NIPSCO MATS Compliance Plan Projects capital expenditure amounts exceed the Commission-approved amounts, that excess and the incremental AFUDC associated with the capital expenditure amounts above approved amounts should not be approved at this time and need to be addressed following a public hearing as part of the Commission's ongoing review; (3) NIPSCO must adhere to the same stakeholder reporting and meeting requirements that were imposed on it in Section 5.E of the Commission's December 28, 2011 Phase I Order in Cause No. 44012; and (4) NIPSCO must make a compliance filing with the Commission with regard to establishing a plan to manage the price risk associated with its Activated Carbon and Fuel Additive purchase costs associated with its MATS Compliance Plan.

D. **Petitioner's Rebuttal Testimony.**

i. **Rebuttal Testimony of Timothy R. Caister.** Mr. Caister testified that the one-year pilot for Fuel Additives projects for Units 7, 8, 12, 14 and 15 is a win-win scenario for customers. Mr. Caister stated that Mr. Blakley's position that "NIPSCO's entire MATS Compliance Plan Project cost recovery should be governed by IC 8-1-8.4" would require the Commission to: (1) ignore the plain language of Ind. Code § 8-1-8.4-6(a); (2) read into Ind. Code Ch. 8-1-8.4 language that is simply not there; and (3) ignore the plain language of Ind. Code § 8-1-2-6.8 and Ind. Ch. 8-1-8.8. In response to Mr. Phillips' suggestion that a new rider could be used for the MATS Compliance Plan Projects, Mr. Caister testified that NIPSCO does not believe it is necessary to create a new tracking mechanism for the MATS Compliance Plan Projects. Mr. Caister stated that the ECRM and EERM are well-established rate adjustment mechanisms for environmental compliance project costs. Finally, Mr. Caister testified that NIPSCO commits to provide updates and/or further information regarding the Bailly Unit 7 ACI project and the Bailly Unit 8 ESP high voltage compartment decks (as well as others) through its semi-annual progress reports filed in its Cause No. 42150-ECR-X filings to the extent that any of these items or subjects cause a change in the scope, schedule or cost estimate for any of the MATS Compliance Plan Projects.

ii. **Rebuttal Testimony of Kelly R. Carmichael.** Mr. Carmichael testified that NIPSCO disagrees with the OUCC's position regarding the Fuel Additives projects. He indicated that the Company does not agree with the OUCC that there must be 100% certainty of a one-year payback period for each of the five (5) proposed Fuel Additives projects in order to approve them. Mr. Carmichael stated that if one or more of the Fuel Additives projects are successful, customers will reap the benefits of reduced O&M expenses for years to come, so the relevant payback period should not be limited to one year. He testified that the OUCC's concerns regarding the risks associated with the assumed injection rates for ACI are far outweighed by the benefits associated with reduced O&M expenses. Mr. Carmichael also testified that NIPSCO believes its assumptions regarding the baseline AC injection rate are reasonable and based on sound information, but even if there is some uncertainty regarding the injection rates, the real cost savings driver is in the reduction in ACI usage.

Mr. Carmichael also testified that IDEM approved NIPSCO's request for a one-year extension of the MATS compliance deadline for Units 12, 14 and 15. Mr. Carmichael stated that disallowance of the Fuel Additives projects would increase the overall O&M costs to customers because the O&M expenses associated with ACI will increase significantly over the estimates set forth in Petitioner's Exhibit No. MH-1. Finally, in response to Mr. Alvarez's testimony, Mr. Carmichael testified that the FGD bypass stack can only be used in limited start-up conditions and that NIPSCO does not believe that the MATS rule will result in any changes in the operating status and condition of the wet FGD bypass stack.

5. **Commission Discussion and Findings.** Petitioner has separated the MATS Compliance Plan Projects into two distinct projects, the MATS Capital Projects and the O&M Projects. For the MATS Capital Projects, Petitioner has requested relief under Ind. Code § 8-1-2-6.8 and Ind. Code ch. 8-1-8.8. For the O&M Projects, Petitioner has requested relief under Ind. Code ch. 8-1-8.4.

A. **Clean Coal Technology, Qualified Pollution Control Technology, Clean Energy Projects and Federally Mandated Compliance Projects.** As an initial matter, we must determine whether the MATS Capital Projects constitute "clean coal technology" under Ind. Code § 8-1-2-6.8 and Ind. Code § 8-1-8.8-3, "qualified pollution control technology" under Ind. Code § 8-1-2-6.8, and "clean energy projects under Ind. Code § 8-1-8.8-2, and whether the O&M Projects are "federally mandated compliance projects" under Ind. Code § 8-1-8.4-2.

i. **Clean Coal Technology under Ind. Code § 8-1-2-6.8 and Ind. Code § 8-1-8.8-3.**

The term "clean coal technology" or CCT is defined as:

> a technology (including precombustion treatment of coal): (1) that is used in a new or existing energy generating facility and directly or indirectly reduces airborne emissions of sulfur, mercury, or nitrogen oxides or other regulated air emissions associated with the combustion or use of coal; and (2) that either: (A) was not in general commercial use at the same or greater scale in new or existing facilities in the United States at the time of enactment of the federal Clean Air Act Amendments of 1990 (P.L.101-549); or (B) has been selected by the United States Department of Energy for funding under its Innovative Clean Coal Technology program and is finally approved for such funding on or after the date of enactment of the federal Clean Air Act Amendments of 1990 (P.L.101-549).

Ind. Code § 8-1-2-6.8(b).[1]

[1] Under Ind. Code § 8-1-8.8-3, CCT is defined as "a technology (including precombustion treatment of coal): (1) that is used in a new or existing energy production or generating facility and directly or indirectly reduces or avoids airborne emissions of sulfur, mercury, or nitrogen oxides or other regulated air emissions associated with the combustion or use of coal; and (2) that either: (A) was not in general commercial use at the same or greater scale in new or existing facilities in the United States at the time of enactment of the federal Clean Air Act Amendments of 1990 (P.L.101-549); or (B) has been selected by the United States Department of Energy for funding or loan guaranty under an Innovative Clean Coal Technology or loan guaranty program under the Energy Policy Act of 2005, or any successor program, and

NIPSCO Witness Hooper testified that each of the MATS Capital Projects will reduce emissions of pollutants including mercury and PM which are regulated air emissions under the MATS rule. He also testified that none of the MATS Capital Projects included in the MATS Compliance Plan were in general commercial use at the same or greater scale in new or existing facilities in the United States as of January 1, 1989. No party disputed this testimony.

Based on our review of the record evidence, we find that the MATS Capital Projects constitute "clean coal technology" as defined in Ind. Code § 8-1-2-6.8 and Ind. Code § 8-1-8.8-3.

ii. <u>Qualified Pollution Control Property under Ind. Code § 8-1-2-6.8</u>. Ind. Code § 8-1-2-6.8 defines "qualified pollution control property" ("QPCP") as "an air pollution control device on a coal burning energy generating facility or any equipment that constitutes clean coal technology that has been approved for use by the commission and that meets applicable state or federal requirements." Ind. Code § 8-1-2-6.8(c).

Mr. Hooper testified that the MATS Capital Projects are all air pollution control devices that will be used on coal burning energy generating facilities. Mr. Hooper also testified that NIPSCO will obtain all required permits to install these projects and they will meet applicable state or federal requirements. No party disputed this testimony. Based on our review of the record evidence, we find that the MATS Capital Projects are air pollution control devices to be used on coal burning facilities and are CCT designed to meet applicable federal and state environmental laws and regulations. We find that the proposed MATS Capital Projects will allow for the continued burning of coal in Petitioner's generating units by allowing them to comply with applicable state and federal environmental regulations. Accordingly, we find that the MATS Capital Projects constitute "qualified pollution control property" as defined in Ind. Code § 8-1-2-6.8.

iii. <u>Clean Energy Projects under Ind. Code Ch. 8-1-8.8</u>. The term "clean energy projects" ("CEP") includes, among others, "[p]rojects to provide advanced technologies that reduce regulated air emissions from or increase the efficiency of existing energy production or generating plants that are fueled primarily by coal or gases from coal from the geological formation known as the Illinois Basin, ..." Ind. Code § 8-1-8.8-2(1)(B).[2]

We have already concluded that the MATS Capital Projects constitute CCT as defined by Ind. Code § 8-1-8.8-3. Mr. Hooper testified that Unit 7 ACI, Unit 7 Fuel Additives, Unit 8 ACI, Unit 8 Fuel Additives, Unit 12 ACI, Unit 12 Fuel Additives, Unit 14 ACI, Unit 14 Fuel Additives, Unit 14 TR Sets, Unit 15 ACI, Unit 15 Fuel Additives, Unit 15 TR Sets, Unit 17 TR Sets, and Unit 18 TR Sets provide advanced technologies that reduce regulated air emissions from or increase the efficiency of existing energy production or generating plants. The evidence shows that ACI is a relatively new technology. Mr. Hooper stated that very few coal power plants have ACI installed

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is finally approved for such funding or loan guaranty on or after the date of enactment of the federal Clean Air Act Amendments of 1990 (P.L.101-549).

[2] The provisions of the state environmental statutes providing favorable regulatory treatment to projects using Indiana or Illinois Basin coal have been held to be an unconstitutional interference with interstate commerce, but severable from the rest of the statutes which remain valid. *General Motors Corp.* v. *Indianapolis Power & Light Co.,* 654 N.E.2d 752, 763 (Ind. Ct. App. 1995); *Alliance For Clean Coal* v. *Bayh,* 72 F.3d 556 (7th Cir. 1995), *See also* S. *Ind Gas and Electric Co.,* Cause No. 41864, at 7 (Aug. 29, 2001); *N Ind Pub. Servo Co.,* Cause No. 42150, at 5 n. 3 (Jan. 26, 2002); *Indianapolis Power and Light Co.,* Cause No. 42170, at 5 n. 1 (Jan. 14, 2002). We will accordingly not rely upon such statutory provisions as a prerequisite for approval of a certificate of clean coal technology or clean energy projects, to obtain QPCP status or to receive any other authority.

and that it is among the most effective technologies for removing mercury. Mr. Hooper testified that Fuel Additives is also relatively new, it is used in conjunction with ACI to optimize the functionality of ACI. He explained that with Fuel Additives, less activated carbon is required to be injected to remove the mercury. He stated that few coal power plants have Fuel Additives installed.

With respect to High Frequency TR Sets, Mr. Hooper stated that use of this equipment did not begin until after 2000. OUCC Witness Snyder testified that replacing the existing TR Sets with high frequency power supplies ("HFPS") will significantly improve ESP performance. He stated that the improved ESP performance will ensure MATS fine PM emission compliance. Mr. Snyder indicated that the HFPS maintains higher ESP field voltages with greatly reduced sparking, increasing particulate collection and reducing fine PM emissions. He cited a January 2012 article by the Electric Power Research Institute ("EPRI") that reported five case histories where switch mode power supply ("SMPS," another name for HFPS) technology reduced fine PM emissions to the 0.03 lb/mmbtu MATS limit. Mr. Snyder testified that according to the EPRI, these case studies confirmed the significant PM emission reduction potential of SMPS retrofits.

No party disputed that the MATS Capital Projects constituted advanced technology under Chapter 8.8. Based on our review of the record evidence, we find that the MATS Capital Projects constitute advanced technologies that reduce regulated air emissions from existing energy generating plants and therefore find the MATS Capital Projects constitute CEP as defined in Ind. Code § 8-1-8.8-2.

iv. <u>Federally Mandated Compliance Projects under Ind. Code Ch. 8-1-8.4</u>.

Ind. Code § 8-1-8.4-2 provides:

> (a) As used in this chapter, "compliance project" means a project that is: (1) undertaken by an energy utility; and (2) related to the direct or indirect compliance by the energy utility with one (1) or more federally mandated requirements.

The term "federally mandated requirement" is defined as "a requirement that the commission determines is imposed on an energy utility by the federal government in connection with any of the following: (1) The federal Clean Air Act (42 U.S.C. 7401 et seq.)" and also includes "(7) Any other law, order, or regulation administered or issued by the United States Environmental Protection Agency, the United States Department of Transportation, the Federal Energy Regulatory Commission, or the United States Department of Energy." Ind. Code § 8-1-8.4-5.

We have already found that NIPSCO is an "energy utility" as defined by Ind. Code § 8-1-8.4-3. Mr. Caister testified that the MATS rule is a federally mandated requirement because the EPA promulgated and imposed the rule under the federal Clean Air Act with which NIPSCO must comply. Mr. Caister further testified that the MATS Compliance Plan comprises of qualifying compliance projects because they are undertaken by the Company, an energy utility, and are related to the direct or indirect compliance with a federally mandated requirement. Mr. Hooper testified that the O&M Projects are necessary to reduce emissions of mercury and PM to levels required by the MATS rule. Mr. Caister stated that NIPSCO's MATS Compliance Plan Projects include qualifying costs incurred in connection with compliance of the MATS rule.

With respect to the O&M Projects, Mr. Hooper testified that the Precipitator and FGD Mist Eliminator Cleaning O&M project for Units 7 and 8 involves increased frequency of cleaning of Precipitators and common FGD Mist Eliminators throughout the year to ensure compliance with the new emissions limits under MATS. He stated that NIPSCO has included $900,000 per year for this purpose. Mr. Hooper testified the Unit 15 ESP Flow Modeling Project is a one-time project meant to identify flow irregularities that will need to be addressed to comply with MATS. NIPSCO's response to the Commission's Docket Entry Question Hooper 1 indicated that in order to comply with the more stringent PM emissions limits imposed by MATS, the flow distribution into Unit 15 ESP must be improved and that uniform distribution flow is a critical parameter for increasing the efficiency of the ESP to comply with MATS. Finally, Mr. Hooper stated the Schahfer Air and Water Testing program will provide the Company with more distinct data associated with the effectiveness and appropriateness of applying the mercury removal technologies associated with the MATS Compliance Plan. NIPSCO's response to the Commission's Docket Entry Question Hooper 2 indicated that of the proposed $500,000 for Air and Water Testing, Air Testing will cost approximately $375,000 and Water Testing will cost approximately $125,000.

With respect to the Air and Water Testing, we agree with NIPSCO that Air Testing is associated with MATS Compliance. However, we disagree that NIPSCO has demonstrated that Water Testing is federally mandated under the MATS Rule. While such testing may be necessary for NIPSCO to comply with current or future water standards, NIPSCO did not indicate any other federal mandate other than the MATS Rule, which does not pertain to water discharge. Accordingly, we find that NIPSCO has not met its burden to demonstrate the Water Testing is a "compliance project."

Based on our review of the record evidence, we find that the O&M Projects, with the exception of Water Testing, constitute federally mandated "compliance projects" under Ind. Code § 8-1-8.4-2 because they will be undertaken by an energy utility (NIPSCO) and are related to the direct or indirect compliance by NIPSCO with MATS—a federally mandated requirement.

B. <u>MATS Compliance Plan Projects</u>. Petitioner requests the issuance of a CPCN for the MATS Compliance Plan Projects pursuant to Ind. Code chs. 8-1-8.8 and 8-1-8.4.

Initially, we note that there is some dispute among the parties concerning whether Chapter 8.8 provides for the relief sought by NIPSCO. The OUCC and Industrial Group suggest that because NIPSCO is seeking a CPCN, a CPCN can only be issued pursuant to Chapter 8.4, because Chapter 8.8 does not provide for a CPCN. The OUCC also argues that because NIPSCO is seeking relief for a portion of the MATS Compliance Plan Projects under Chapter 8.4, the Commission should consider NIPSCO's entire request for relief under Chapter 8.4. Further, the parties state that Chapter 8.7 does not apply because the MATS Compliance Plan Projects do not reduce sulfur or nitrogen-based pollutants, and thus are not CCT under Chapter 8.7.

The legislature has created multiple avenues for a utility to seek recovery of plant investments, some of which may overlap. However, the fact that a utility has several options for relief does not foreclose the opportunity for the utility to seek relief under multiple avenues. As we noted in *Indianapolis Power & Light*, Cause No. 44242 (IURC Aug. 14, 2013) ("44242 Order"), Chapter 8.8 provides for Commission approval of incentives for clean energy projects, not a CPCN. A CPCN issued under Chapter 8.7 for Chapter 8.7-defined clean coal technology involves consideration of different factors for approval and involves defined procedures for updating the

Commission on a utility's progress. Like NIPSCO, IPL was seeking approval of MATS Compliance Projects, but was seeking approval under Chapters 8.7 and 8.8, not Chapters 8.4 and 8.8. Ultimately, this Commission granted relief under Chapter 8.8 for all of IPL's MATS projects, even though some of them were also subject to Chapter 8.7. Further, the Commission noted that had IPL presented sufficient evidence to obtain a CPCN under Chapter 8.7, the Commission could have granted relief for CCT under Chapter 8.7 and treated the remainder as CEP under Chapter 8.8.

Section 6(a) of Chapter 8.4 similarly provides for multiple avenues of relief. Ind. Code § 8-1-8.4-6(a) states:

> Except as provided in subsection (c), or unless an energy utility has elected to file for:
>
> (1) a [CPCN]; or
>
> (2) the recovery of costs;
>
> under another statute, an energy utility that seeks to recover federally mandated costs under section 7(c) of this chapter must obtain from the commission a certificate that states that public convenience and necessity will be served by a compliance project proposed by the energy utility.

Here, NIPSCO has elected to file for the recovery of its MATS Capital Projects under Chapter 8.8 and recovery of its MATS O&M Projects under Chapter 8.4.[3] Chapter 8.4 explicitly provides that the Commission may grant relief under alternate provisions, and although we agree with the consumer parties that Chapter 8.8 does not provide for a CPCN, we must focus on the nature of the relief requested, which, for purposes of Chapter 8.8, is an approval of financial incentives for CEP. Accordingly, we address the MATS Capital Projects and MATS O&M Projects in turn.

i. <u>Approval for MATS Capital Projects</u>. Petitioner requests approval of the MATS Capital Projects pursuant to Ind. Code ch. 8-1-8.8. Indiana Code § 8-1-8.8-11 provides that "[a]n eligible business must file an application to the commission for approval of a clean energy project" and that "[t]he commission shall encourage clean energy projects by creating [certain] financial incentives for clean energy projects, if the projects are found to be reasonable and necessary." As discussed above, NIPSCO is an "eligible business" for purposes of Chapter 8.8, and the MATS Capital Projects constitute clean energy projects under Ind. Code § 8-1-8.8-2(1)(B). Accordingly, we must determine whether the MATS Capital Projects are reasonable and necessary.

The extensive evidence presented by NIPSCO and the OUCC provides a thorough description of MATS. We find that MATS establishes new direct and surrogate emission standards based upon the MACT to address HAPs including mercury and fine PM for NIPSCO's coal-fired generators. The compliance deadline for NIPSCO's Units 7, 8, 17 and 18 is three years after the effective date of the MATS rule or April 16, 2015. The compliance deadline for NIPSCO's Units 12, 14 and 15 is April 16, 2016 because NIPSCO has been granted a one-year extension based upon a demonstration that additional time is needed in order to install control technology.

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[3] While NIPSCO's Verified Petition in this Cause suggests that Chapter 8.7 may apply, its MATS Compliance Projects do not reduce sulfur or nitrogen-based pollutants, and NIPSCO's proposed order did not reference Chapter 8.7.

The evidence shows that NIPSCO cannot currently meet the MATS emissions limits. NIPSCO Witness Carmichael and OUCC Witness Armstrong provided evidence regarding the specific emissions applicable to NIPSCO. Mr. Carmichael testified that mercury continuous emissions monitors ("CEMs") data from Bailly Units 7 and 8 has historically fluctuated above and below the MATS standard of 1.2 lb/TBtu and that Michigan City Unit 12 and Schahfer Units 14 and 15 have typically emitted more than the MATS standard. Mr. Carmichael also indicated that Bailly and Michigan City Unit 12 have at times in the past exceeded the MATS standard for PM. Further, he said Schahfer Units 14, 15, 17 and 18 risk exceeding the limit when continuously monitored (under the MATS rule, each unit must comply at all times during operation). Ms. Armstrong testified that NIPSCO's coal-fired generating units are not able to meet the MATS limits at this time.

The evidence provided by NIPSCO Witness Carmichael and OUCC Witness Armstrong shows that the MATS rule is a command and control standard that prescribes MACT-based limits for HAPs and does not contemplate a flexible emissions allowance trading program. As a result, we find there are essentially two primary compliance options for NIPSCO: (1) retire some or all of NIPSCO's coal-fired generation units and replace the retired energy and capacity (i.e. retire and replace); or (2) install pollution control equipment to reduce regulated emissions (i.e. retrofit).

With respect to the "retire and replace" option, NIPSCO Witness Largura testified that NIPSCO's simulation analysis showed the cost to be greater than the retrofit option. She described Strategist®, a software system that the Company uses to support electric utility decision analysis and corporate strategic planning such as its integrated resource planning process. Ms. Largura listed the key inputs in the Strategist® model: compliance options' capital, O&M costs; discount rate; correlated fuel supply costs and electricity market prices for capacity and energy; carbon prices; and customers' peak and energy needs. Ms. Largura testified that the results of the analysis demonstrate that NIPSCO's MATS Compliance Plan is the preferred option for reliably and cost effectively serving its customers today and in the future while addressing environmental requirements and the inherent uncertainties and risks associated with the electricity industry. She indicated that the initial conclusions from the Strategist® analysis were that the installation of control equipment is preferred. The NPVRR[4] for the MATS Compliance Plan was $12,421,670 and the option to retire all coal stations yielded a NPVRR of $14,730,430, a difference of $2,308,760 from the preferred plan.

Ms. Largura also testified that the breakpoints in her analysis demonstrate further that the retrofit is the clear choice. She indicated that natural gas cost breakpoints that favored the capital investments at Bailly Units 7 and 8 occurred at or above: (1) $2.49/MMBtu (2012 natural gas price, escalating annually at 6.68%); (2) $4.37/MMBtu (2012 natural gas price, escalating annually at 2%); and (3) $5.16/MMBtu (2012 natural gas price, escalating annually at 0%). NIPSCO's Response to IURC Docket Entry Question Largura 3 clarified that natural gas prices above these values favor retrofitting all units (including Bailly Units 7 and 8) with the MATS Compliance Plan Projects and that these are the price points below which NIPSCO would exclude the investments at Bailly Units 7 and 8 but still invest in the remaining MATS Compliance Plan Projects. Ms. Largura testified that an escalation in capital cost breakpoint analysis indicates that escalation in capital cost for MATS Compliance Plan Projects has virtually no impact on the decision. In fact, according to Ms. Largura, costs of the MATS Capital Projects would have to rise more than 1,000% for each unit

[4] All NPVRR dollars cited herein are stated in 2011 nominal dollars in thousands.

in order to change the decision. Finally, Ms. Largura testified that carbon price breakpoints that favored the capital investments at Bailly Units 7 and 8 occurred at or below \$32.73/ton in 2020. NIPSCO's Response to the Commission's Docket Entry Question Largura 3 clarified that this is the carbon price breakpoint at which NIPSCO would exclude the Bailly Units 7 and 8 projects but still invest in the remaining MATS Compliance Plan Projects.

OUCC Witness Rutter testified that the MATS Compliance Plan is consistent with NIPSCO's 2011 IRP and that the economic analysis supporting the Plan was based on reasonable assumptions of costs and circumstances for each of the alternatives tested based on what is known today. Mr. Rutter's testimony supports the conclusion that the cost of the retire and replace option is greater than the MATS Compliance Plan. He did state that there is some degree of risk associated with the MATS Compliance Plan because of evolving EPA regulations, but not enough evidence to suggest it should be rejected. Based on our review of the record evidence, we find that the cost of the "retire and replace" option would be greater than installing pollution control equipment to achieve compliance. However, we must also evaluate the alternative project portfolios identified and discussed by NIPSCO and the OUCC.

Mr. Hooper testified that in developing the MATS Compliance Plan, NIPSCO evaluated many different types of pollution control equipment, including the full set of projects identified in the S&L Report and other technologies including a filterable PM strategy, the installation of high frequency TR Sets, upgrading the rapping systems, replacing the ESP internals, adding an additional field or additional plate area to the ESP, converting part of the ESP to a baghouse, converting existing ESP into a baghouse, an O&M project strategy, ESP cleaning, mist eliminator cleaning, ESP flow modeling, a mercury removal strategy, FGD units, fuel additives, wet FGD re-emission additives, ACI and a mercury oxidation catalyst. He stated that NIPSCO also explored the option of changing coal sources for Bailly Units 7 and 8 in lieu of installing ACI and Fuel Additives facilities, but that the economics show that making the capital investments is the preferred option.

Mr. Hooper testified that NIPSCO selected a subset of the projects identified in the S&L Report for its MATS Compliance Plan. He stated that the S&L Report is a zero-compliance risk option, but NIPSCO is looking to balance capital cost with the compliance margin risk while ensuring that all of the projects are supported by emissions test data. Mr. Hooper stated that ultimately, NIPSCO selected the projects in the MATS Compliance Plan over the alternatives that it considered because it believes the projects included in its MATS Compliance Plan represent the most cost-effective option for each unit to comply with the mercury and PM emissions limits imposed by the MATS rule considering the emissions test data, implementation schedule, risks, compliance margin and fuel and operating cost considerations.

Mr. Carmichael and Mr. Hooper testified that the MATS Capital Projects will provide significant reduction in mercury and fine PM emissions. Mr. Hooper and Mr. Carmichael testified that the TR Sets will reduce PM emissions. Mr. Hooper also indicated that the ACI and Fuel Additives projects will reduce mercury emissions. Mr. Carmichael described the Fuel Additives projects and indicated they will have the effect of increasing the amount of oxidized mercury in the flue gas to a level greater than 90% of the total mercury and that oxidized portion is then readily captured in the downstream pollution control devices. Mr. Carmichael and Mr. Hooper each testified that NIPSCO anticipates that the MATS Capital Projects will be successfully constructed and operated by the compliance deadline set forth in the MATS rule. Mr. Hooper did add that although the data and analysis indicate that the current suite of projects included in NIPSCO's

MATS Compliance Plan will allow for MATS compliance, if after a period of operation there remain areas where sufficient compliance margin does not exist, NIPSCO may seek to perform additional activities in order to meet the compliance requirements. Mr. Hooper testified that this is neither anticipated nor expected; however, it should not be excluded from the conversation either.

With respect to the Fuel Additives projects, Mr. Carmichael testified they are designed to add halogenated compounds to coal and thus to the combustion process. He stated that Fuel Additives systems, such as calcium bromide and calcium chloride, are a low capital cost option for improving mercury capture for units equipped with pollution controls, including FGD technology, that have a low proportion of oxidized mercury to elemental mercury. Mr. Carmichael testified that the potential O&M cost savings to customers from using Fuel Additives during the one year Fuel Additives pilot alone outweighs the capital cost of the Fuel Additives facilities as well as the Fuel Additives O&M. Therefore, even if use of Fuel Additives is not allowed after the one year Fuel Additives pilot due to adverse water impacts, the capital and O&M costs associated with the Fuel Additives pilot would be offset by the reduction in ACI O&M costs during the one year pilot period.

The OUCC supports approval of NIPSCO's proposed MATS Capital Projects except for the Fuel Additives projects. Specifically, the OUCC recommends that the Commission deny approval for the Fuel Additives projects for Units 7, 8, 12, 14 and 15. OUCC Witness Armstrong testified that although the Fuel Additives systems may provide economic benefits and operational flexibility, NIPSCO may have overstated the units' AC injection rate, which would then alter the cost effectiveness of installing and testing the Fuel Additives systems. Importantly, Ms. Armstrong stated that the projects' payback periods must be less than a year for the OUCC to support a CPCN for these systems, as this is the time period for which NIPSCO has secured a variance from IDEM on its National Pollutant Discharge Elimination System ("NPDES") permits to test the impacts of the fuel additives. Further, Ms. Armstrong stated that if NIPSCO has assumed an overstated AC injection rate for these units – which is a concern raised by other OUCC witnesses, then the cost effectiveness of the Fuel Additives systems may not be enough to warrant installing and testing them in a one-year pilot. Finally, she expressed concerns about the possibility of the fuel additive negatively affecting the water effluent quality and a possibility of not receiving IDEM's approval. OUCC Witness Alvarez testified that a critical component in determining the economic feasibility of the Fuel Additives pilot project is the activated carbon injection rate needed to attain compliance and without a clear understanding of the AC injection rate level, a high degree of uncertainty exists regarding the economic analysis provided by NIPSCO. OUCC Witness Snyder testified that if the initial ACI feed rate is much less than the rate assumed by NIPSCO in its analysis, there may not be enough reduction in ACI usage possible to justify the Fuel Additives projects. OUCC Witness Eke testified that the industry standard AC injection rates for a unit similar to Unit 12 with a baghouse/fabric filter and Selective Catalytic Reduction is 2 lb/MMacf and that if that rate is assumed for Unit 12, the payback period for the Unit 12 Fuel Additives project would be 3.48 years.

In rebuttal, NIPSCO Witness Carmichael testified that the Company does not agree with the OUCC that there must be 100% certainty of a one-year payback period for each of the five proposed Fuel Additives projects in order to approve them. He stated that for a project, even a seven year payback period could be considered an attractive capital investment because utilities need to consider investments to serve customers cost-effectively over the long-term, not just one-year payback cycles. Mr. Carmichael also testified that if only one of the Fuel Additives projects is successful, customers will reap the benefits of reduced O&M expenses for years to come.

Petitioner's Exhibit No. KRC-2 (Confidential) shows the annual savings by unit. Mr. Carmichael said that the Company must weigh these substantial future benefits against the relatively small risk that: (a) none of the projects will be allowed to continue past the one-year trial period; and (b) the O&M savings achieved during the one-year trial period is significantly less than NIPSCO has assumed in Petitioner's Exhibit No. KRC-2 (Confidential).

Mr. Carmichael indicated that the OUCC's concerns regarding the risks associated with the assumed injection rates for ACI are far outweighed by the benefits associated with reduced O&M expenses. Mr. Carmichael also testified that NIPSCO believes its assumptions regarding the baseline AC injection rate are reasonable and based on sound information, but even if there is some uncertainty regarding the injection rates, the real cost savings driver is in the reduction in ACI usage. Additionally, he stated that (1) NIPSCO anticipates that within the one year trial, the capital cost of the Fuel Additives projects will be recovered via avoided O&M costs and that (2) the opportunity for long term cost saving benefits far outweigh the risks associated with sunk capital investment. He testified that NIPSCO believes that the recommended disallowance of the Fuel Additives projects would increase the overall O&M costs to customers because the O&M expenses associated with ACI will increase significantly over the estimates set forth in Petitioner's Exhibit No. MH-1.

We note that under Chapter 8.8, we must determine whether CEP is "reasonable and necessary." This Commission's determination of what is "reasonable and necessary" is afforded broad discretion. While Chapter 8.8 does not set forth any specific factors the Commission should consider in determining the reasonableness and necessity of a clean energy project, the Commission has considered some factors outlined in Chapter 8.7 in other cases. *See Northern Indiana Public Service Co.*, Cause No. 44012 (Phase I Order), at 20 (IURC Dec. 28, 2011) (discussing effect of compliance project on operations and comparing cost of retirement); *see also Indiana Michigan Power Co.*, Cause No. 44182, at 53-54 (IURC July 17, 2013) (Chapter 8.7 factors relevant for LCM Project under Chapter 8.8).

With respect to the Fuel Additives projects, NIPSCO's economic analysis suggests there is a strong possibility that the customer payback period will be less than one year, which suggests that even if the projects must be shut down after one year, customers will benefit. Even if the payback period is greater than one year, the Fuel Additives projects should still be in the public interest. The OUCC's evidence shows that even with a much lower assumed injection rate, the payback period would still be less than four years. So long as the Fuel Additives projects do not negatively affect water effluent quality, customers will benefit from the reduced ACI O&M expenses in future years. We therefore conclude that NIPSCO's proposed one-year pilot for the Fuel Additives projects for Units 7, 8, 12, 14 and 15 should be approved as part of NIPSCO's MATS Compliance Plan.

Ultimately, we find that the MATS Capital Projects, including the Fuel Additives projects, present a MATS compliance option with a reasonable balance of costs, risks and policy based upon consideration of all the factors impacting the decision, including uncertainties about the future and those factors that are known at this time. Specifically, we find that the MATS Capital Projects are a commercially appropriate solution to allow NIPSCO to: (1) comply with MATS; (2) provide the required amount of energy and capacity to NIPSCO's customers; (3) meet the deadlines imposed by MATS; and (4) mitigate various risks. The MATS Capital Projects, including the Fuel Additives projects, balance capital costs with the risk of compliance and is supported by emissions test data. Finally, we note that most of NIPSCO's coal-fired generation units (Units 7, 8, 12, 14, 17 and 18) burn some coal sourced from the Illinois Basin[5] and the evidence shows that if the MATS Compliance Plan Projects are not installed, NIPSCO would be required to shut down its coal-fired generation units as of April 16, 2015. As we discussed above, the MATS Capital Projects constitute "clean energy projects" under Ind. Code § 8-1-8.8-2. We find that the MATS Capital Projects are reasonable and necessary to reduce mercury and fine PM emissions from NIPSCO's coal-fired generating units, and approve the MATS Capital Projects pursuant to Ind. Code § 8-1-8.8-11.

We note that under our public interest review of the MATS Capital Projects, it is appropriate for the Commission to tie its reasonable and necessary finding, whether implicitly or explicitly, to the cost estimate (with an appropriate range of accuracy) and underlying analysis provided by the petitioning utility in order to determine the viability of the proposed project. As we explained in our Phase I Order in Cause No. 44012, "the initial granting of a CPCN depends in large part upon the economic efficacy of a proposed project, and as such, the initial cost estimates are a significant factor in the Commission's decision making process." *NIPSCO*, Cause No. 44012 Phase I Order, at 18 (IURC Dec. 28, 2011). Similarly, we find that the MATS Capital Projects are reasonable and necessary so long as the final cost of the MATS Capital Projects do not exceed $74.1 Million (excluding AFUDC), subject to our ongoing review discussed in Para. 5(D). As noted in Para. 5(B)(3)(A) below, through this Order we are only approving the recovery of NIPSCO's estimated cost of $59.28 Million.

Based on the record evidence, we find that NIPSCO's construction, implementation and use of the MATS Capital Projects are reasonable and necessary under Chapter 8.8 based on the estimated cost, range of accuracy, and the associated analysis provided by NIPSCO.

ii. CPCN for O&M Projects. For the O&M Projects, Petitioner requests the issuance of a CPCN pursuant to Ind. Code Ch. 8-1-8.4. In order to grant a CPCN under Ind. Code Ch. 8-1-8.4, we must find that the O&M Projects will allow NIPSCO to comply directly or indirectly with one (1) or more federally mandated requirements and we must examine each of the following factors described in Ind. Code § 8-1-8.4-6(b):

> (1) The following, which must be set forth in the energy utility's application for the certificate sought, in accordance with section 7(a) of this chapter:
>
> > (A) A description of the federally mandated requirements, including any consent decrees related to the federally mandated requirements, which the energy utility seeks to comply with through the proposed compliance project.
> >
> > (B) A description of the projected federally mandated costs associated with the proposed compliance project, including costs that are allocated to the energy utility:
> >
> > > (i) in connection with regional transmission expansion planning and construction; or
> > > (ii) under a Federal Energy Regulatory Commission approved tariff, rate schedule, or agreement.

[5] As discussed in footnote 3 above, we will not use the Indiana or Illinois Basin coal requirement as a prerequisite for approval of a certificate of CCT, to obtain QPCP status, or to receive any other authority.

(C) A description of how the proposed compliance project allows the energy utility to comply with the federally mandated requirements described by the energy utility under clause (A).

(D) Alternative plans that demonstrate that the proposed compliance project is reasonable and necessary.

(E) Information as to whether the proposed compliance project will extend the useful life of an existing energy utility facility and, if so, the value of that extension.

(2) Any other factors the commission considers relevant.

With respect to factor 1(A), we find there was substantial evidence submitted by Petitioner and the OUCC concerning the MATS rule, which is the federally mandated requirement. With respect to factor 1(B), NIPSCO's evidence, including the direct testimony of Mr. Hooper and the Responses to the IURC Docket Entry Questions provided a detailed description of the projected federally mandated costs associated with the O&M Projects. This evidence is discussed in detail in Section C below.

With respect to factor 1(C), Mr. Hooper's testimony and the Responses to the Commission's Docket Entry Questions provided evidence regarding how the O&M Projects will allow Petitioner to comply with the MATS rule, with the exception of the Water Testing project. NIPSCO did not demonstrate how the Water Testing project helps it achieve compliance with the MATS Rule. In the Commission's view, the purpose of the Water Testing project is to allow NIPSCO to demonstrate compliance with NPDES limits due to the Fuel Additives pilot project, not to show compliance with MATS. While we have found the Fuel Additives projects to be reasonable and necessary pursuant to Chapter 8.8, those projects are not federally mandated, and NIPSCO could comply with MATS without undertaking the Fuel Additives pilot. Accordingly, we find that while NIPSCO has sufficiently demonstrated how the remaining O&M Projects will allow NIPSCO to comply with the MATS rule, it did not meet its burden to show that the Water Testing project will allow NIPSCO to comply with the MATS rule.

With respect to factor 1(D), as discussed above in Paragraph 5B(i) with respect to the MATS Capital Projects, we similarly find that the cost of the MATS O&M Projects is less than the "retire/replace" alternative for MATS compliance. We also find that the MATS O&M Projects constitute a MATS compliance option with a reasonable balance of costs, risks and policy based upon consideration of all the factors impacting the decision. Finally, with respect to factor 1(E), as discussed in Paragraph 5B(i) above, we similarly find that without the MATS O&M Projects, NIPSCO would be required to shut down its coal-fired generation units as of April 16, 2015 and so the O&M Projects will extend the useful economic life of NIPSCO's facilities.

Based on our review of the record evidence, we find that the O&M Projects, with the exception of the Water Testing project, will allow NIPSCO to comply directly or indirectly with MATS—a federally mandated requirement, and we have made a finding on each of the factors described in Ind. Code § 8-1-8.4-6(b). We therefore approve the O&M Projects, with the exception of the Water Testing project, pursuant to Ind. Code Ch. 8-1-8.4 and find that NIPSCO's request for a CPCN for the O&M Projects, with the exception of the Water Testing project, should be granted, limited to the estimated cost of the projects as set forth by NIPSCO.

iii. Cost Estimate.

A. **MATS Capital Projects**. Petitioner requests approval of the cost estimates for the MATS Capital Projects set forth in Petitioner's Exhibit No. MH-1. The estimated costs for the MATS Capital Projects, excluding AFUDC, are as follows: Unit 7 ACI - $3,966,402; Unit 7 FA - $531,240; Unit 8 ACI - $7,932,918; Unit 8 FA - $1,064,760; Unit 12 ACI - $6,614,280; Unit 12 FA - $1,596,000; Unit 14 ACI - $6,614,850; Unit 14 FA - $1,596,000; Unit 14 TR Sets - $4,389,000; Unit 15 ACI - $6,614,850; Unit 15 FA - $1,596,000; Unit 15 TR Sets - $4,389,000; Unit 17 TR Sets - $6,187,350; and Unit 18 TR Sets - $6,187,350. The details of these cost estimates are set forth in Petitioner's Exhibit No. MH-4 (Confidential).

Mr. Hooper testified that the total estimated costs for the MATS Capital Projects is $59.28 million. He stated that this represents $52 million of direct capital, $7.28 million of indirect capital and excludes AFUDC. Mr. Hooper indicated that in accordance with the Association for the Advancement of Cost Engineering Cost Estimate Classification System, the cost estimate as a whole ranges from $44.46 million ($39 million direct capital and $5.46 million indirect capital) to $74.1 million ($65 million direct capital and $9.1 million indirect capital). He identified several factors that could drive actual capital costs towards the top end of the range: (1) escalation beyond what the Company has already estimated due to a crowded market as many utilities perform similar work at the same time in order to meet the MATS compliance deadline; (2) an untimely issuance of a CPCN order could compress installation schedules and costs could rise as a result of the need to expedite the work; (3) if the one-year Fuel Additives pilot is unsuccessful or is cancelled, the O&M costs associated with ACI would likely rise; (4) an increase in the commodity prices of the activated carbon and the fuel additive chemicals could affect the annual O&M expenses for ACI and Fuel Additives projects.

OUCC Witness Alvarez testified that the total project cost estimate in a multi-project plan typically represents the sum of all proposed projects approved by the Commission. He stated that cancelling any single project fundamentally changes the overall compliance plan from a regulatory standpoint. Mr. Alvarez testified that the OUCC expects that if Petitioner needs to modify the costs of any project that it will inform the Commission and interested parties of this need in one of the regularly docketed proceedings. He stated that if Petitioner decides to cancel a project or make material changes to the projects or cost of the projects, the OUCC recommends that the Commission require Petitioner to seek a modification to its CPCN so that all interested parties have an opportunity to review and comment on the requested change. Industrial Group Witness Dauphinais testified that NIPSCO's cost estimates for capital projects fall into a class that could have actual expenditures as much as 30% lower or as much as 50% higher than estimated and that NIPSCO identified a number of factors that could drive its actual capital expenditure amounts towards the 50% over estimate level.

The evidence presented sufficiently describes the projected costs associated with the MATS Capital Projects and demonstrates that the projects offer substantial potential to cost effectively reduce pollutants in a more efficient manner than alternative methods of complying with the MATS rule. Based on our review of the record evidence, we find that NIPSCO's cost estimates for the MATS Capital Projects of $59.28 Million, as depicted in Petitioner's Exhibit No. MH-1, are reasonable and should be approved. Consistent with the recommendations of OUCC Witness Alvarez and Industrial Group Witness Dauphinais, to the extent the MATS Capital Project costs exceed this amount, these increased costs and incremental AFUDC associated with project costs above $59.28 Million are not approved at this time and would need to be addressed in a separate docketed proceeding.

B. **MATS O&M Project.** NIPSCO also requests approval of the cost estimates for the O&M Projects set forth in Petitioner's Exhibit No. MH-1. The estimated costs for the O&M Projects are: Unit 7 Precipitator & FGD Mist Eliminator Cleaning - $300,000 per year; Unit 8 Precipitator & FGD Mist Eliminator Cleaning - $600,000 per year; Unit 15 ESP Flow Modeling - $200,000 in 2013 and $100,000 in 2014; Units 14, 15, 17 and 18 Air and Water Testing - $500,000 total. In its Response to the Commission's May 30, 2013 Docket Entry, NIPSCO indicated that the Water Testing portion, which we have not approved for a CPCN, is estimated to cost $125,000.

Pursuant to Ind. Code 8-1-8.4-7(c), if the Commission approves a proposed compliance project and the projected federally mandated costs associated with the proposed compliance project, the following apply:

> (1) Eighty percent (80%) of the approved federally mandated costs shall be recovered by the energy utility through a periodic retail rate adjustment mechanism that allows the timely recovery of the approved federally mandated costs. The commission shall adjust the energy utility's authorized net operating income to reflect any approved earnings for purposes of IC 8-1-2-42(d)(3) and IC 8-1-2-42(g)(3).
>
> (2) Twenty percent (20%) of the approved federally mandated costs, including depreciation, allowance for funds used during construction, and post in service carrying costs, based on the overall cost of capital most recently approved by the commission, shall be deferred and recovered by the energy utility as part of the next general rate case filed by the energy utility with the commission.
>
> (3) Actual costs that exceed the projected federally mandated costs of the approved compliance project by more than twenty-five percent (25%) shall require specific justification by the energy utility and specific approval by the commission before being authorized in the next general rate case filed by the energy utility with the commission.

NIPSCO has demonstrated that the federally mandated MATS O&M Project costs (excluding Water Testing), as set forth above, are reasonable. Accordingly, we find the projected MATS O&M Project costs (excluding Water Testing) should be approved for purposes of Ind. Code 8-1-8.4-7(c).

C. **Ratemaking Treatment and Depreciation.**

i. **Ratemaking Treatment under Ind. Code § 8-1-2-6.8.** Petitioner requests a finding that the MATS Capital Projects constitute "qualified pollution control property" and are eligible for the ratemaking treatment described in Ind. Code § 8-1-2-6.8. Specifically, Petitioner requests authorization to utilize CWIP ratemaking treatment for CCT and QPCP (and clean energy projects) consistent with and through Petitioner's currently-effective ECRM. Petitioner also requests authorization to accrue AFUDC related to QPCP prior to CWIP ratemaking treatment or their reflection of such costs in NIPSCO's electric rates and a finding that the MATS Capital Projects are deemed to be under construction until such time the Commission determines that the MATS Capital Projects are used and useful in a proceeding that involves the establishment of new electric basic rates and charges for Petitioner. Petitioner also requests authorization to recover through rates pre-construction costs incurred prior to approval of a Final Order in this proceeding through Petitioner's currently-effective ECRM. We address preconstruction costs under the Chapter 8.8 financial incentives.

NIPSCO Witness Isensee testified that NIPSCO's proposed CWIP ratemaking treatment would include all capital expenditures related to QPCP and clean energy projects within NIPSCO's MATS Compliance Plan, in the semi-annual ECRM filings. Mr. Isensee stated that the ECRM, which was originally authorized by the Commission in its November 26, 2002 Order in Cause No. 42150, is a semi-annual recovery mechanism designed to recover a return on capital expenditures associated with approved environmental compliance projects. Specifically, he testified that NIPSCO proposes to add to the value of NIPSCO's property on which the Company is authorized to earn a return the value of the qualified pollution control property and clean energy projects after such project has been under construction for at least six months. He indicated that CWIP ratemaking treatment will be calculated based on NIPSCO's weighted average cost of capital used to calculate the return on capital expenditures and will use the return on common equity most recently approved by the 43969 Order.

We have already determined that the MATS Capital Projects constitute "qualified pollution control property" as defined in Ind. Code § 8-1-2-6.8. As a result, we find the MATS Capital Projects are eligible for the ratemaking treatment described in Ind. Code § 8-1-2-6.8. Indiana Code § 8-1-2-6.8(e) provides: "Upon the request of a utility that begins construction after March 31, 2002, of qualified pollution control property that is to be used and useful for the public convenience, the commission shall for ratemaking purposes add to the value of that utility's property the value of the qualified pollution control property under construction." We therefore authorize NIPSCO to utilize CWIP ratemaking treatment and AFUDC treatment for the MATS Capital Projects consistent with and through Petitioner's currently-effective ECRM, and we hereby deem the MATS Capital Projects to be under construction until such time the Commission determines that the Projects are used and useful in a proceeding that involves the establishment of new electric basic rates and charges for Petitioner. We find that NIPSCO should be and hereby is authorized to accrue AFUDC on MATS Capital Projects costs up to the approved amounts set forth above.

ii. Financial Incentives under Ind. Code § 8-1-8.8-11. As discussed above, we find that the MATS Capital Projects constitute "clean energy projects" and are reasonable and necessary and are therefore eligible for financial incentives under Ind. Code Ch. 8-1-8.8-11. Petitioner requests, among other things, authorization to utilize CWIP ratemaking treatment for its clean energy projects (and CCT and QPCP) and to recover O&M expenses relating to the MATS Capital Projects, including depreciation expense, for its clean energy projects (and CCT and QPCP) consistent with and through Petitioner's currently-effective ECRM and EERM. Indiana Code § 8-1-8.8-11 provides:

> (a) The commission shall encourage clean energy projects by creating the following financial incentives for clean energy projects, if the projects are found to be reasonable and necessary:

(1) The timely recovery of costs and expenses incurred during construction and operation of projects described in section 2(1) or 2(2) of this chapter.

* * * * *

(5) Other financial incentives the commission considers appropriate.

Having found that the MATS Capital Projects constitute "clean energy projects" that are reasonable and necessary and therefore eligible for the financial incentives set forth in Ind. Code § 8-1-8.8-11(a)(1), we therefore approve NIPSCO's request for timely recovery of costs and expenses incurred during construction and operation of the MATS Capital Projects consistent with and through Petitioner's currently-effective ECRM and EERM.

The OUCC and Industrial Group opposed NIPSCO's recovery of preconstruction costs under Ind. Code § 8-1-2-6.8 because that section does not reference preconstruction costs. The consumer parties note that preconstruction costs are referenced in other law applicable to CCT that are solely for nitrogen or sulfur-based pollutant reduction, which as previously discussed, do not apply to the MATS Compliance Projects.

While we agree with the consumer parties with respect to the silence on preconstruction costs under Section 6.8, preconstruction costs were included in the cost estimates of the CEP that the Commission has approved in this Order. Given the legislative mandate to encourage CEP, we see no reason that preconstruction costs should not be timely recovered in connection with the recovery of other "post-construction" costs subject to Ind. Code § 8-1-8.8-11(a)(1). We further note that no party challenged the reasonableness of NIPSCO's preconstruction costs. To the extent that recovery of preconstruction costs would constitute "other" financial incentives under Ind. Code 8-1-8.8-11(a)(5), we find that timely recovery of costs and expenses incurred in the preconstruction phase, as set forth in NIPSCO's cost estimate, is appropriate.

iii. <u>Ratemaking Treatment for Incremental O&M Projects</u>. NIPSCO Witness Hooper testified that NIPSCO's MATS Compliance Plan includes several incremental O&M projects necessary to reduce emissions of mercury and PM to levels required by the MATS rule. The O&M Projects include: Precipitator and FGD Mist Eliminator Cleaning (Units 7 and 8), ESP Flow Modeling (Unit 15), and Air and Water Testing (Units 14, 15, 17 and 18).

NIPSCO Witness Camp testified that NIPSCO proposes to recover 80% of the actual O&M Project expenses through the currently-effective EERM. She testified that NIPSCO proposes to defer 20% of the actual O&M expenses associated with its federally mandated O&M Projects as a regulatory asset for recovery as part of NIPSCO's next general rate case. NIPSCO witness Isensee testified that rather than creating a new tracking mechanism, NIPSCO is proposing to include 80% of all O&M Project expenses in the annual EERM filings in order to recover such project expenses in a timely manner. He stated these expenses would be treated consistently with O&M expenses recovered as part of NIPSCO's NOx Compliance Plan, CAIR/CAMR Compliance Plan and Multi-Pollutant Compliance Plan.

We have found that the O&M Projects, with the exception of the Water Testing project, constitute federally mandated compliance projects under Ind. Code Ch. 8-1-8.4, and that these projects should receive a CPCN and their projected costs should be approved. Based on our review of the record evidence, we find that NIPSCO's proposed "80/20" ratemaking treatment of the approved O&M Projects is consistent with Ind. Code § 8-1-8.4-7 and that it is reasonable for NIPSCO to include these costs for recovery in its currently-effective EERM rather than creating a new tracking mechanism for this subset of MATS Compliance Plan Projects.

iv. Cost Allocation. NIPSCO Witness Isensee testified that NIPSCO proposes ratemaking treatment for the MATS Compliance Plan Projects identified in Petitioner's Exhibit No. MH-1 consistent with and through its existing ECRM and EERM tracking mechanisms. Although Mr. Isensee did not specifically address a proposed method to allocate costs relating to its MATS Compliance Plan Projects, we assume NIPSCO's proposal to treat the MATS Compliance Plan Projects consistently with projects approved as part of NIPSCO's NOx Compliance Plan, CAIR/CAMR Compliance Plan and Multi-Pollutant Compliance Plan includes using the same cost allocation method as is currently used for the ECRM and EERM. We note that in ECR 19, the Commission approved the 12 coincident peak method ("12 CP") to allocate costs of environmental projects among the various customer classes, and that decision was ultimately affirmed on appeal.

Industrial Group Witness Phillips testified that NIPSCO had allocated QPCP fixed costs to classes on the basis of firm load of the four summer coincident peaks ("4 CP") method for many years and deducted interruptible load. He testified that the 4 CP method was changed to the 12 CP method without subtracting interruptible load in ECR 19. He disagrees with allocating new costs associated with the MATS Compliance Plan projects using the 12 CP method because the current approved base rates for NIPSCO are not a result of the 12 CP method and no cost of service study or cost of service allocation method was approved in the 43969 Order. Mr. Phillips testified that the settling parties in Cause No. 43969 utilized an across-the-board approach modified for residential mitigation and other considerations to achieve the revenue allocation for cost responsibility under the new rates and resulting rate increase to classes. Mr. Phillips testified that Joint Exhibit C to the Settlement approved in the 43969 Order—the revenue requirement allocation is the most reasonable method to allocate fixed MATS costs to customer classes. Mr. Phillips testified that one way to address his concern is a new rider separate from the existing ECRM and EERM for recovery of approved MATS costs. He testified another possibility is that NIPSCO could continue to use the existing ECRM and EERM tracking mechanisms and prepare a separate schedule for the allocation of the MATS project costs using the Industrial Group's recommended allocation method.

NIPSCO Witness Caister testified that NIPSCO believes the ECRM and EERM are well-established rate adjustment mechanisms for environmental compliance project costs. They provide an opportunity to review all of the QPCP, CCT and CEP costs in one set of mechanisms. NIPSCO does not believe it is necessary to create a new tracking mechanism for the MATS Compliance Plan Projects.

Based on our review of the record evidence, we find that NIPSCO's proposal to treat the MATS Compliance Plan Projects consistently with projects approved as part of NIPSCO's NOx Compliance Plan, CAIR/CAMR Compliance Plan and Multi-Pollutant Compliance Plan through its existing ECRM and EERM is reasonable and appropriate. We find this approach necessarily includes using the same cost allocation method as is currently used for the ECRM and EERM, and the Commission previously addressed the allocation issues in ECR 19. We therefore decline to adopt the Industrial Group's recommendation that approved MATS costs be allocated using the negotiated revenue allocations from the 43969 Settlement, or that MATS costs be tracked in a separate rider.

v. **Depreciation Treatment.** NIPSCO requests authority to depreciate the MATS Capital Projects according to the composite remaining life approved in the 43969 Order once each project is placed in service. Ind. Code § 8-1-2-19 gives us authority to "ascertain and determine the proper and adequate rates of depreciation" and gives us authority to "make changes in such rates of depreciation, from time to time, as it may find necessary." We find that NIPSCO's proposal to depreciate the MATS Capital Projects based on the depreciation rates established in NIPSCO's most recent electric base rate case is reasonable and should be approved.

D. Ongoing Review, Semi-Annual Progress Reports and Reporting Requirements. NIPSCO requests ongoing review of the MATS Capital Projects as part of the semi-annual progress reports filed as part of each ECRM filing in Cause No. 42150-ECR-XX. We note that NIPSCO has regularly reported to the Commission on the progress of its approved CCT, QPCP, and CEP by its annual progress reports in Cause Nos. 42515, 42737, 42935, 43144, 43371, 43593, 43840 and semi-annual progress reports in 42150-ECR-19 through 42150-ECR-21.

The Commission noted in Cause No. 44242 that under Chapter 8.8, there is no explicit provision for ongoing review. *See* 44242 Order at 37. However, the Commission found that ongoing review was reasonable in order to provide timely recovery of costs pursuant to Ind. Code § 8-1-8.8-11. We further noted that such review would be limited to approving costs and expenses up to the approved cost estimate. *Id.* Accordingly, we find that NIPSCO shall provide updates to the MATS Capital Projects through its semi-annual ECRM proceedings.

OUCC Witness Alvarez included several other recommendations for ongoing reporting relating to: (1) Bailly Unit 7 injected activated carbon residence time; (2) the Pure Air Flue Gas Processing Agreement for the Bailly wet FGD; (3) changes in the operating status of the Bailly wet FGD bypass smokestack under the compliance provisions of the MATS rule; and (4) corrosion mitigation and control plan for Bailly Unit 8 ESP high voltage compartment decks. NIPSCO agreed to provide updates and/or further information regarding the Bailly Unit 7 activated carbon project and the Bailly Unit 8 ESP high voltage compartment decks (as well as others) through its semi-annual progress reports filed in its Cause No. 42150 ECR X filings to the extent that any of these items or subjects cause a change in the scope, schedule or cost estimate for any of the MATS Compliance Plan Projects. This would include any changes due to the Pure Air Flue Gas Processing Agreement for the Bailly wet FGD. We agree that NIPSCO should include updates and/or further information regarding these matters in its semi-annual progress reports filed in its Cause No. 42150 ECR X filings to the extent that any of these items or subjects may impact the scope, schedule or cost estimate for any of the MATS Compliance Plan Projects. We find that NIPSCO Witness Carmichael adequately addressed Mr. Alvarez's question regarding changes in the operating status of the Bailly wet FGD bypass smokestack in his rebuttal testimony. He testified that NIPSCO does not believe the MATS rule will result in any changes in the operating status and condition of the wet FGD bypass stack.

Industrial Group Witness Dauphinais recommended that NIPSCO be required to adhere to the same stakeholder reporting and meeting requirements that were imposed on it in Section 5.E of the Commission's December 28, 2011 Phase I Order in Cause No. 44012 (the "Phase I Order"). In its proposed order, NIPSCO indicated that because the MATS Compliance Plan Projects involve less cost and much shorter construction schedules than the Unit 14 and 15 FGD projects approved in Phase I Order, NIPSCO's internal meeting and reporting will not be the same for the MATS Compliance Plan Projects. However, NIPSCO proposed the following reporting and meeting obligations:

1. On a quarterly basis, NIPSCO will provide a status report for the TR Set projects until the TR Set projects are placed in service.

2. On a quarterly basis, NIPSCO will provide a status report for the ACI projects until the ACI projects are placed in service.

3. The quarterly TR Set and ACI reports will, at a minimum, contain information regarding: (1) whether the in-service date for the project has been delayed and a detailed explanation of the reason for any delay that has developed since the last previously reported scheduled completion date; (2) whether the total cost estimate for the project has changed and a detailed explanation of any deviations that have developed since the last previously reported projected total cost for the project; and (3) an update with regard to the risks associated with the project.

4. Once the Fuel Additive projects are in service, NIPSCO will include detailed testimony in its ongoing review proceedings providing updates regarding: (1) the results of air and water testing during the one-year pilot periods; and (2) NIPSCO's MATS compliance plan based on the results of the air and water testing.

5. NIPSCO will meet upon request by the OUCC, Industrial Group, and other interested stakeholders that have executed a non-disclosure agreement to discuss the MATS Compliance Plan Projects until the last of the projects goes into service subject to the understanding that some NIPSCO personnel may need to conduct some of the meetings via conference call, video conference, or other remote means to reduce travel time and accommodate project management staff schedules.

Mr. Dauphinais also recommended that NIPSCO be required to make a compliance filing with the Commission with regard to establishing a plan to manage the price risk associated with its activated carbon and fuel additive purchase costs associated with its MATS Compliance Plan. NIPSCO indicated that it is too early to know whether a formal "plan" to manage the price risk associated with activated carbon and fuel additive purchase costs is necessary or possible. However, NIPSCO agreed to provide an update and detailed explanation of the market for activated carbon and fuel additives and the options NIPSCO is reviewing to manage the price risk associated with its activated carbon and fuel additive purchase costs in its direct testimony in Cause No. 42150 ECR 25 (to be filed in February 2015). NIPSCO indicated that it will be closer to making procurement decisions at that time. NIPSCO also noted that the Industrial Group will be free to make the same recommendation at that point if it is still concerned about price risk. We find that the extra meeting and reporting obligations to which NIPSCO has agreed are reasonable. We therefore find that NIPSCO should comply with the five ongoing reporting and meeting requirements enumerated herein and provide an update regarding the options NIPSCO is reviewing to manage the price risk associated with its activated carbon and fuel additive purchase costs in its direct testimony in Cause No. 42150 ECR 25.

E. Dispatching priority for the facilities utilizing CCT, QPCP, and clean energy projects. By its Verified Petition, NIPSCO requested authority to perform dispatch of its generation units in a manner necessary to comply with the MATS requirements or other environmental regulations or requirements and that the Commission declare such procedures to be in compliance with current and future dispatch parameters relating to the recovery of fuel costs. NIPSCO Witness Hooper testified that to the extent that the operation of any of these projects increases the variable operating costs to run a unit, it is possible that the units' dispatching priority may change.

Industrial Group challenged NIPSCO's request, stating that the relief was not appropriate as part of this proceeding, but should be addressed as part of the Commission's review of fuel costs under Indiana Code 8-1-2-42. As previously noted, dispatch priority is an element we must consider for a CPCN under Chapter 8.7. *See also Northern Ind. Public Serv. Co.*, Cause No. 44012 Phase III Order at 23-24 (addressing dispatch priority as part of CPCN approval for CCT). Although Chapter 8.8 contains no similar requirement, we recognize that NIPSCO must comply with the emissions limits set forth in MATS, and NIPSCO may need to change priority of dispatch, short term generation levels, or take an outage to maintain compliance with emission limitations. NIPSCO's request is consistent with the Commission's recognition that Indiana utilities may sometimes need to change their priority of dispatch or short term generation levels for environmental purposes such as environmental derates. *See id.* at 24 (listing numerous cases). NIPSCO, as a responsible generating plant operator, must comply and should be supported in its pursuit to comply with the state and federal environmental regulations. Therefore, we find that NIPSCO's request to perform dispatch of its generation units in a manner necessary to comply with MATS is reasonable.

F. Confidentiality. Petitioner filed a motion for protective order on February 22, 2013 which was supported by affidavit showing documents to be submitted to the Commission were trade secret information within the scope of Ind. Code §§ 5-14-3-4(a)(4) and (9) and Ind. Code § 24-2-3-2. The Presiding Officers issued a Docket Entry on April 26, 2013 finding such information to be preliminarily confidential, after which such information was submitted under seal. We find 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. Petitioner shall be and is hereby issued an approval for the MATS Capital Projects pursuant to Ind. Code ch. 8-1-8.8, and a CPCN for the O&M Projects, with the exception of the Water Testing project, pursuant to Ind. Code ch. 8-1-8.4. This Order constitutes the Certificate.

2. The cost estimates for the MATS Compliance Plan Projects set forth in Para. 5B above shall be and are hereby approved.

3. The MATS Capital Projects shall be and hereby are determined to constitute "qualified pollution control property" and "clean coal technology" and are eligible for the ratemaking treatment described in Ind. Code § 8-1-2-6.8.

4. The MATS Capital Projects shall be and hereby are determined to constitute "clean energy projects" under Ind. Code ch. 8-1-8.8-1, and are hereby approved as reasonable and necessary and therefore eligible for the financial incentives set forth in Ind. Code § 8-1-8.8-11.

5. The MATS O&M Projects approved herein shall be and hereby are determined to constitute "federally mandated compliance projects," and the costs incurred in connection with the O&M Projects shall be and hereby are determined to be "federally mandated costs" under Ind. Code ch. 8-1-8.4-1, and are therefore eligible for the ratemaking treatment described in Ind. Code § 8-1-8.4-7.

6. Petitioner shall be and hereby is authorized to utilize construction work in progress ratemaking treatment for qualified pollution control property and clean energy projects consistent with and through Petitioner's currently-effective ECRM tracking mechanism and the MATS Capital Projects shall be deemed to be under construction until such time the Commission determines that they are used and useful in a proceeding that involves the establishment of new electric basic rates and charges for Petitioner.

7. Petitioner shall be and hereby is authorized to accrue allowance for funds used during construction relating to the MATS Capital Projects.

8. Petitioner shall be and hereby is authorized to depreciate the MATS Capital Projects according to depreciation rates approved in Cause No. 43969.

9. Petitioner shall be and hereby is authorized to recover reasonably incurred O&M expenses and depreciation expenses relating to the MATS Capital Projects consistent with and through Petitioner's currently-effective EERM tracking mechanism pursuant to Ind. Code § 8-1-8.8-11.

10. Petitioner shall be and hereby is authorized to recover 80% of the approved federally mandated costs incurred in connection with the O&M Projects through Petitioner's currently-effective EERM tracking mechanism pursuant to Ind. Code § 8-1-8.4-7.

11. Petitioner shall be and hereby is authorized to defer depreciation and O&M expenses relating to the MATS Capital Projects until such expenses are recovered through Petitioner's currently-effective EERM tracking mechanism.

12. Petitioner shall be and hereby is authorized to defer 20% of the approved federally mandated costs incurred in connection with the O&M Projects which the Petitioner will be authorized to recover in Petitioner's next general rate case pursuant to Ind. Code § 8-1-8.4-7.

13. Petitioner shall be and hereby is authorized to recover through Petitioner's currently effective ECRM mechanism pre-construction costs for its Capital Projects incurred prior to and after approval of a Final Order in this proceeding to the extent that such costs are described in Petitioner's cost estimate approved herein.

14. Petitioner is authorized to seek timely recovery of the MATS Compliance Plan Projects as part of Petitioner's semi-annual progress reports filed in Cause No. 42150-ECR-XX, as set forth herein.

15. Petitioner shall be and hereby is authorized to perform dispatch of its generation units in a manner necessary to comply with the requirements of the MATS and declaring such procedures to be in compliance with current and future dispatch parameters relating to the recovery of fuel costs.

16. Petitioner shall comply with the ongoing reporting and meeting requirements enumerated in Para. 5D.

17. The information filed by Petitioner in this Cause pursuant to its 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.

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

ATTERHOLT, BENNETT, LANDIS, MAYS AND ZIEGNER CONCUR:

APPROVED: OCT 10 2013

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

Brenda A. Howe

Brenda A. Howe
Secretary to the Commission