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STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY FOR APPROVAL OF 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 AND 8-1-8.7 AND 170 IAC 4-6-1, *ET SEQ.* AND THE COMMISSION'S ORDERS IN CAUSE NOS. 42150, 43188, 43913, 43969 AND 44012, APPROVAL OF ITS PROGRESS REPORT AND APPROVAL OF MODIFICATIONS OF AND REVISED COST ESTIMATES RESPECTING CLEAN COAL TECHNOLOGY UNDER THE ONGOING REVIEW PROCESS APPROVED IN CAUSE NOS. 42150, 43188, 43913 AND 44012 PURSUANT TO IND. CODE § 8-1-8.7.	)	**CAUSE NO. 42150 ECR 19** **APPROVED:** MAY 02 2012

ORDER OF THE COMMISSION

Presiding Officers:
David E. Ziegner, Commissioner
Aaron A. Schmoll, Senior Administrative Law Judge

On February 7, 2012, Northern Indiana Public Service Company ("Petitioner", "Company" or "NIPSCO") petitioned the Indiana Utility Regulatory Commission ("Commission") for approval of (1) an adjustment to its electric service rates through its Environmental Cost Recovery Mechanism ("ECRM") and Environmental Expense Recovery Mechanism ("EERM") factors to reflect costs incurred in connection with the construction of its Qualified Pollution Control Property ("QPCP"), (2) its progress report, and (3) modifications of and revised cost estimates respecting Clean Coal Technology ("CCT") under the ongoing review process approved in Cause Nos. 42150, 43188, 43913, and 44012 pursuant to Ind. Code Ch. 8-1-8.7. NIPSCO also prefiled direct testimony of its witnesses Ronald Plantz, Thomas Titus and Curt Westerhausen on February 7, 2012.

On February 23, 2012, the NIPSCO Industrial Group ("Industrial Group") filed its Petition to Intervene, which was subsequently granted. On March 1, 2012, the Presiding Administrative Law Judge participated in an informal teleconference with the Parties at which time agreed procedural dates in this Cause were established. A Docket Entry dated March 6, 2012 set forth the agreed procedural dates. On April 3, 2012, the Indiana Office of Utility Consumer Counselor ("OUCC") prefiled direct testimony of its witnesses Wes R. Blakley and Dale E. Swan and the Industrial Group prefiled direct testimony of its witness Nicholas Phillips, Jr. On April 10, 2012, NIPSCO prefiled rebuttal testimony of Mr. Westerhausen, OUCC prefiled cross-answering testimony of Tyler E. Bolinger and Dr. Swan and the Industrial Group prefiled cross-answering testimony of Mr. Phillips. On April 12, 2012 the Commission issued a docket entry directing Petitioner to respond to questions, to which Petitioner responded on April 16, 2012.

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 April 17, 2012 at 9:30 a.m., in Room 222, PNC Center, 101 West Washington Street, Indianapolis, Indiana. At the hearing, Petitioner, OUCC and Industrial Group all presented their respective evidence, without objection. Petitioner also presented its responses to the Commission's April 12, 2012 Docket Entry, without objection. No member of the public appeared or participated at the hearing.

The Commission, having considered the evidence and being duly advised, now finds that:

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, Ind. Code § 8-1-2, and is subject to the jurisdiction of the Commission, in the manner and to the extent provided by Indiana law. The Commission has jurisdiction over the Petitioner and subject matter of this case.

2. **Petitioner's Characteristics and Generating System.** 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 November 26, 2002 in Cause No. 42150 (the "42150 Order"), the Commission approved (1) NIPSCO's proposed ECRM as set forth in its Rule 47, which provides for ratemaking treatment of NIPSCO's QPCP pursuant to Ind. Code §§ 8-1-2-6.6, 8-1-2-6.8, and 8-1-8.7-7, (2) NIPSCO's proposed EERM as set forth in its Rule 48, which provides for recovery of operation and maintenance and depreciation expenses related to NIPSCO's QPCP in service, and (3) 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").

By its Orders in Cause Nos. 42515 (2/4/04), 42737 (1/19/05), 42935 (12/21/05) and 43144 (12/13/06), the Commission approved revisions to NIPSCO's NOx Compliance Plan.

By its Order in Cause No. 43188 (7/3/07), the Commission approved NIPSCO's plan to comply with the U.S. Environmental Protection Agency's ("EPA") Clean Air Interstate Rule ("CAIR") and Clean Air Mercury Rule ("CAMR") (the "CAIR/CAMR Compliance Plan"), which was designed to achieve additional reductions of sulfur dioxide ("SO2"), nitrogen oxide ("NOx") and Mercury ("Hg") emissions.

By its Orders in Cause Nos. 43371 (12/19/07), 43593 (1/14/09) and 43840 (7/7/10), the Commission approved revisions to NIPSCO's NOx Compliance Plan and CAIR/CAMR Compliance Plan (referred to collectively as the "Compliance Plan").

By its Order in Cause No. 43913 (12/29/10), the Commission approved NIPSCO's request for a certificate of public convenience and necessity ("CPCN") pursuant to Ind. Code § 8-1-8.7 for the construction of additional CCT in the form of wet flue gas desulfurization ("FGD") facilities at its R.M. Schahfer facility on Unit 14, along with additional facilities to be used jointly with the adjacent Unit 15.

By its Order in Cause No. 42150 ECR 17 (4/27/11) ("ECR-17 Order"), the Commission approved NIPSCO's report on the progress of its Compliance Plan and modifications to its Compliance Plan, including revised cost estimates, construction start, in-service dates, and scope additions for NIPSCO's CCT pursuant to Ind. Code § 8-1-8.7 under the ongoing review process approved in Cause Nos. 42150, 43188 and 43913.[1]

By its Phase I Order in Cause No. 44012 (12/28/11) ("Phase I 44012 Order"), the Commission approved NIPSCO's request for a CPCN for Unit 15 FGD Additions, and NIPSCO's revised cost estimates for the Unit 14 wet FGD and Common Facilities previously approved in the 43913 Order (the "Phase I Projects"). The Phase I Projects are part of NIPSCO's Multi-Pollutant Compliance Plan ("MPCP"). The Commission approved Petitioner's cost estimates for the Phase I Projects, which were $203 million for the Unit 14 FGD, $104 million for the Common Facilities, and $193 million for the Unit 15 FGD.

By its Phase II Order in Cause No. 44012 (2/15/12) ("Phase II 44012 Order"), the Commission approved NIPSCO's request for a CPCN for five CCT projects, including (1) Unit 7 Selective Catalytic Reduction ("SCR") Duct Burners; (2) Unit 8 SCR Duct Burners; (3) Unit 14 SCR Duct Burners; (4) Unit 15 SNCR Installation; and (5) Continuous Particulate Monitors Addition for Units 7, 8, 14, 15, 17 and 18 (the "Phase II Projects"). The Phase II Projects are also part of NIPSCO's MPCP. The Commission also approved Petitioner's cost estimates for the Phase II Projects ($11 million for the Unit 7 SCR Duct Burners, $16 million for the Unit 8 SCR Duct Burners, $16 million for the Unit 14 SCR Duct Burners, $6 million for the Unit 15 SNCR Installation, $375,000 for the Unit 15 Continuous Particulate Monitors Addition, $375,000 for the Unit 14 Continuous Particulate Monitors Addition, $375,000 for the Unit 17 Continuous Particulate Monitors Addition, $375,000 for the Unit 18 Continuous Particulate Monitors Addition, $375,000 for the Units 7 and 8 Continuous Particulate Monitors Addition common stack and $375,000 for the Units 7 and 8 Continuous Particulate Monitors Addition bypass stack).

In Cause No. 43969, NIPSCO sought approval of changes to its basic rates and charges for electric service. In that Cause, NIPSCO also requested approval to reflect 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-

[1] The Commission's August 25, 2010 Order in Cause No. 43526 ordered Petitioner to file its Annual Progress Reports on the status of QPCP tracked in the ECRM as part of its ECRM filings rather than a separate cause.

service at the end of the test year (the twelve months ended June 30, 2010) and that are currently being recovered through the ECRM, and adjusting the ECRM to eliminate costs relating to those projects upon the effective date of the new base rates and charges approved therein, subject to any necessary variance reconciliations. By its Order in Cause No. 43969 (12/21/11) (the "2011 Rate Order"), the Commission approved a Stipulation and Settlement Agreement by and among NIPSCO, the OUCC, NLMK Indiana f/k/a Beta Steel Corporation, Indiana Municipal Utilities Group, and Industrial Group (the "2011 Settlement") which provided for new basic rates and charges. New electric tariffs as a result of the 2011 Rate Order, including new ECRM and EERM factors, became effective December 27, 2011. As a result of the 2011 Rate Order, the projects included for recovery in NIPSCO's ECRM have changed significantly from the projects included in ECR-17 (approved by the Commission Order in Cause No. 42150 ECR 17 (4/27/11)) ("ECR-17 Order") and ECR-18 (approved by the Commission Order in Cause No. 42150 ECR 18 (10/25/11)) ("ECR 18 Order"). A number of NIPSCO's QPCP projects approved in Cause Nos. 42150 and 43188 were included in the base rates approved in Cause No. 43969 and will no longer be tracked through the ECRM. As noted in the 2011 Rate Order, EERM factors are approved after the expenses have occurred and therefore, NIPSCO continued to defer the operating & maintenance ("O&M") and depreciation related to the NOx projects that were added to rate base in Cause No. 43969 until the December 27, 2011 effective date of new electric rates, and all such deferred costs will be recovered in the appropriate EERM filing. Specifically, this filing reflects O&M and depreciation expenses incurred during the time period January 1, 2011 through December 26, 2011 for projects which are now in rate base.

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

a. Billing Period. NIPSCO witness, Mr. Westerhausen, 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 of NIPSCO electric utility customers in the months of May 2012 through October 2012. He stated the ECRM factors include actual costs through December 2011, as well as a reconciliation of projected period recoveries of ECRM revenue with actual revenue during the period May 1, 2011 through October 31, 2011.

b. QPCP Investment. Mr. Westerhausen testified the total cost of QPCP under construction, net of accumulated depreciation, upon which NIPSCO is authorized to earn a return is $109,566,909. 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. Westerhausen testified that if the Commission approves the proposed ratemaking treatment for the value shown in Schedule 1A of Exhibit 1 attached to the Company's Verified Petition initiating this Cause, NIPSCO will cease accruing AFUDC on those costs.

NIPSCO witness, Mr. Titus, testified that Schedules 1 and 1A of Exhibit 1 (the Verified Petition initiating this Cause) describe the Company's QPCP under construction on which NIPSCO proposes to earn a return. Schedules 1 and 1A set out (1) a brief description of the project, (2) approved cost estimates, (3) the construction start dates, (4) the anticipated in-service dates, and (5) the current and prior QPCP values for each project. He testified that the costs for the Company's QPCP projects have been compiled through December 31, 2011. Mr. Titus also testified that all of the projects for which the Company is seeking ratemaking treatment in this Cause have been under construction for at least 6 months.

Mr. Titus explained that NIPSCO updated the Schedules to reflect changes due to the 2011 Rate Order (projects that were included in rate base by effect of the 2011 Rate Order have been removed from Schedules 1 and 1-A of Exhibit 1). He testified that NIPSCO also updated Schedules 1 and 1-A of Exhibit 1 to include the Phase I Projects approved by the Phase I 44012 Order. Mr. Titus added that because NIPSCO anticipated that the Commission would issue a final order approving the Phase II Projects prior to the May 1, 2012 effective date of the new ECRM and EERM factors proposed in this proceeding, NIPSCO also updated Schedules 1 and 1-A of Exhibit 1 to include the Phase II Projects.[2]

OUCC witness, Mr. Blakley, testified that many of NIPSCO's QPCP construction projects have been moved into rate base as a result of the 2011 Rate Order and are no longer in the calculation of revenue requirement. He also testified that projects approved in the Phase I 44012 Order and Phase II 44012 Order are included in this tracker.

Based on the record evidence, we find that NIPSCO's request to begin earning a return on \$109,566,909, the value of its QPCP, net of accumulated depreciation, is reasonable and should be approved.

c. <u>Semi-Annual Revenue Requirement</u>. In this proceeding, NIPSCO requests approval of a Semi-Annual Revenue Requirement of \$5,617,802 and an Adjusted Semi-Annual Revenue Requirement of \$4,990,505 after adjusting for the prior period reconciliation.

Mr. Plantz computed Petitioner's proposed semi-annual return on its QPCP at December 31, 2011 of \$5,617,802, which is the product of Petitioner's QPCP value multiplied by its weighted cost of capital, adjusted for taxes and multiplied by 0.50. Petitioner's Exhibit 1, Schedule 7 shows that Petitioner's Adjusted Semi-Annual Revenue Requirement is \$4,990,505 after including the prior period reconciliation.

Mr. Plantz sponsored the calculation of NIPSCO's 6.79% weighted cost of capital, using its regulatory capital structure, per books, at December 31, 2011, which is the date of valuation of the QPCP in accordance with 170 IAC 4-6-14. He testified the cost rates for long-term debt and preferred stock reflect the 12 months ended December 31, 2011. 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 states 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. Blakley testified that on Petitioner's Exhibit, 1, Schedule 7, NIPSCO calculated a semi-annual revenue requirement amount for its ECRM to cover return on investment. He testified that the total Indiana jurisdictional amount plus prior reconciliations results in

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[2] As noted above, the Commission approved NIPSCO's request for a CPCN for the Phase II Projects by its Phase II 44012 Order.

$4,990,505 to be recovered in the ECRM in this proceeding. Mr. Blakely further testified that based on his own review and analysis, nothing came to his attention that would indicate that NIPSCO's calculation of its ECRM revenue requirements is unreasonable.

Based on the record evidence, we find that NIPSCO's proposed Adjusted Semi-Annual Revenue Requirement of $4,990,505 is reasonable and should be approved.

d. Allocation of Semi-Annual QPCP Revenue Requirement. Prior to the 2011 Rate Order, NIPSCO allocated QPCP fixed costs to classes on the basis of the four summer coincident peak ("4 CP") method approved in the Settlement of Cause No. 42150. That allocation method was based on the production allocation approved in the Settlement of Cause No. 41746.

In Cause No. 43969 (NIPSCO's most recent base rate case), the allocation of NIPSCO's revenue requirement was set forth in Joint Exhibit C (Base Rate Revenue Requirement Allocation) to the 2011 Settlement ("Joint Exhibit C Allocation").

Although the 2011 Settlement provides that the costs relating to NIPSCO's two new rate adjustment mechanisms to track Regional Transmission Organization and Resource Adequacy costs should be allocated using the 12 CP method set forth in Joint Exhibit E to the 2011 Settlement, neither the 2011 Settlement nor the 2011 Rate Order prescribe an allocation method for NIPSCO's ECRM and EERM rate adjustment mechanisms. Because the 2011 Settlement lacked an agreement on the allocation of QPCP costs, the Commission ordered NIPSCO to put forth a proposal for the allocation of QPCP costs in its first ECR filing following approval of the 2011 Settlement. NIPSCO provided two alternate proposals for the allocation of QPCP costs in this proceeding.

Mr. Westerhausen sponsored Schedule 5 of Exhibit 1 which shows the production allocation percentages attributable to each of the Company's rate schedules based on the demand allocators shown in Joint Exhibit E to the 2011 Settlement (the Production Rate Base allocated by the rate classes' 12 Coincident Peaks ("12 CP")) ("Joint Exhibit E Allocation").

Mr. Westerhausen also sponsored Petitioner's Exhibit No. CAW-2, Exhibit 1 Schedule 5 - Alternative which shows the production allocation percentages attributable to each of the Company's rate schedules based on the Joint Exhibit C Allocation Base Rate Revenue Requirement Allocation.

The OUCC recommends an allocation methodology on the basis of class energy at the generator for the allocation of ECRM costs. To support this recommendation, Dr. Swan testified that the Company's proposal to allocate 100 percent of ECRM costs on the basis of class contributions to the 12 CP is incorrect because all of these costs are caused directly by the production of energy through the conversion of fuel into kilowatt-hours, with the attendant production of regulated emissions. He stated it is the need to reduce these emissions, which are a by-product of the production of energy, that causes these costs to be incurred.

Dr. Swan testified that if the Commission wishes to retain a coincident peak allocation for a portion of these costs, the Commission should utilize a Peak and Average ("P&A") allocator (based on 65 percent of class energy responsibility and 35 percent of class responsibility for the four summer peaks).

Dr. Swan testified that if the Commission is reluctant to move away from a coincident peak allocation method, the next best solution would be to approve the Company's proposal to allocate 100 percent of the ECRM costs based on class responsibility for the twelve monthly system coincident peaks (the Joint Exhibit E Allocation). While Dr. Swan opined that coincident peaks are the wrong aspects of class usage to use for allocation of these energy-driven costs, the 12 CP is the broadest standard coincident peak allocator and is far preferable to a narrower definition of peak, such as the four summer peaks. Dr. Swan stated the OUCC would be willing to accept either the P&A or the 12 CP (the Joint Exhibit E Allocation) as a reasonable compromise.

The Industrial Group recommends the Joint Exhibit C Allocation (Base Rate Revenue Requirement Allocation) as the appropriate method. To support this recommendation, Mr. Phillips testified the Joint Exhibit C Allocation reflects the method prescribed by applicable law; reflects the manner in which the Settling Parties agreed that cost responsibility is shared among the customer classes; no agreement on a cost of service method was approved in the 2011 Rate Order; the end result of a cost of service study is the allocation of revenue requirement to the rate classes and therefore the agreed upon and approved allocation parameters of base rate revenue requirement by class is the appropriate method of allocation of qualified pollution control cost in this proceeding; previous costs associated with QPCP were rolled-in to base rates using the Joint Exhibit C Allocation; and if the Joint Exhibit E Allocation is used, it must be adjusted to remove interruptible loads from Rates 632, 633 and 634.

Mr. Phillips testified it is clear that no cost of service method was approved in the 2011 Rate Order and that problems existed with the data required for the development of basic allocation methods. He stated the allocation parameter used to determine the cost responsibility of each customer class is the allocation of the base rate revenue requirement (cost responsibility) to customer classes agreed to by the Settling Parties and approved by the Commission in its 2011 Rate Order. Mr. Phillips opined that use of this allocation parameter is consistent with the allocation of previously approved QPCP costs to classes in NIPSCO's new base rate and does not harm the residential class. He testified NIPSCO has used the 4 CP method in each ECR filing for approximately the last ten years and, therefore, the Joint Exhibit E Allocation would result in a shift in cost allocation without any documented change in operations or generation stations. Mr. Phillips stated the Commission and Settling Parties have established the allocation of fixed QPCP costs to classes in accordance with the allocation parameters established in Joint Exhibit C.

OUCC witness Mr. Bolinger responded to Mr. Phillips' discussion of the allocation parameters established in Joint Exhibit C. He testified that Joint Exhibit C is plainly and accurately labeled as the "Allocation of Base Rate Revenue Requirement," which was used to allocate NIPSCO's entire jurisdictional base rate revenue requirement approved in the 2011 Rate Order, which includes all the relevant components of NIPSCO's cost of service, including fixed and variable distribution, transmission and generation costs. He stated Joint Exhibit C represents the Settling Parties agreement on the allocation of the entire base rate revenue requirement – not individual component parts such as QPCP costs.

As to Mr. Phillips' contention that the Commission and Settling Parties have established the allocation of fixed QPCP costs to classes in accordance with the allocation parameters established in Joint Exhibit C, Mr. Bolinger noted that he was extensively involved with the team that represented the OUCC in the negotiations that led to the 2011 Settlement and testified there is no agreement among the Settling Parties regarding the allocation of QPCP costs, Joint Exhibit C provides the allocation parameters for the entire NIPSCO base rate revenue requirement, and there is absolutely no agreement that Joint Exhibit C be used to allocate QPCP costs. Mr. Bolinger testified the 2011 Rate Order ordered NIPSCO to put forth a proposal for the allocation of QPCP costs in its first ECR filing following the 2011 Rate Order. He noted that NIPSCO has done that, the OUCC and Industrial Group have responded, and there is no accord among the parties to the Settlement to use Joint Exhibit C for the allocation parameters for QPCP costs.

As to Mr. Phillips' suggestion that the Joint Exhibit C Allocation provides the proper allocation parameters for allocating the ECR costs in this proceeding, Dr. Swan testified Mr. Phillips is incorrect in suggesting that there is some kind of presumptive requirement to use the Joint Exhibit C Allocation as the basis for allocating fixed ECR costs in this proceeding. He stated that use of that allocator makes no sense because it is based on no cost causative theory and would essentially continue to impose further unwarranted increases on small and medium general service customers.

As to Mr. Phillips' criticism of NIPSCO's switch to the use of the Joint Exhibit E Allocation, Dr. Swan testified that NIPSCO was responding to the Commission's directive in its August 25, 2010 Order in Cause No. 43526 ("43526 Order") when it recommended a 12 CP allocation of the fixed ECR costs and that Mr. Phillips' criticism should be ignored.

Dr. Swan testified that Mr. Phillips' proposal for an adjustment to NIPSCO's Joint Exhibit E Allocation to eliminate interruptible load if the Commission decides to allocate the fixed ECR costs using the 12 CP would give a free ride to the largest energy users and causers of environmental emissions and should be rejected by the Commission.

Dr. Swan testified there is nothing in Mr. Phillips' testimony that alters the obvious conclusion that it is the conversion of coal fuel into kilowatt-hours that has caused the environmental emissions and therefore has caused the Company to incur the fixed costs of QPCP to abate those emissions in compliance with new restrictive environmental regulations. Therefore, Dr. Swan continues to recommend that the most cost-causative allocation of those fixed costs among the customer classes is (1) a 100 percent energy allocation, using kWh at generator, or (2) a P&A allocation of these costs as a reasonable compromise, or (3) NIPSCO's proposed Joint Exhibit E Allocation (without adjustment for interruptible load) in the spirit of compromise.

Mr. Phillips testified Dr. Swan's approach to the forms of energy allocations are completely unreasonable and inappropriate because (1) they are not in any manner in accordance with the allocation parameters established by the Commission in the 2011 Rate Order, (2) fixed cost associated with investment in production plant previously has not been allocated on an energy allocator or the P&A allocator, (3) NIPSCO's current QPCP is allocated to classes based on the 4 CP method adjusted to provide a credit for interruptible loads, and (4) they are based on outdated data.

As to the OUCC's additional recommendations, Mr. Phillips pointed out that the Commission explicitly ruled on this issue in other QPCP proceedings and endorsed a demand based allocation for QPCP costs, and that the OUCC has previously advocated that the recovery of QPCP costs should be consistent with past practice.

As to the OUCC's compromise recommendation for the use of the P&A method, Mr. Phillips pointed out that the OUCC advocated the use of the P&A method in a previous base rate proceeding, which the Commission denied. He stated that Dr. Swan generally uses a load factor analysis to determine the amount of production investment that he proposes to allocate on an energy basis. He noted that Dr. Swan also proposed an alternative method of arriving at the energy component of fixed production costs, using the replacement cost of peaking units and that the data Dr. Swan has used to support his recommended allocations is outdated.

Mr. Phillips testified there is no relationship set forth by Dr. Swan that proves that energy use is appropriate for the classification of production plant. He stated that the appropriate application of cost causation principles is that fixed costs should be allocated on a demand basis as opposed to an energy basis. Mr. Phillips was not familiar with any Commission precedent that would support the classification and allocation of production on an energy basis.

Mr. Phillips pointed out that Dr. Swan presented no new or relevant facts to justify his recommendation to significantly change the allocation methodology in this case and that the Commission should find that QPCP investment is a fixed cost that is properly classified as demand-related, consistent with its previous findings.

Mr. Phillips pointed out that since Dr. Swan's energy allocation proposals are without merit, his compromise is not really a compromise. He pointed out that the Commission did not approve any method of allocating cost based on cost causation in its 2011 Rate Order, Consequently, there was no approval of the 12 CP methodology and, should the Joint Exhibit E Allocation be used, then the interruptible load must be subtracted to avoid allocating costs to interruptible customers who are not causing those costs. To support his opinion, Mr. Phillips stated that the 2011 Rate Order states that Rider 675 potentially avoids the costs of new generation and higher energy costs, thus it is inconsistent and inappropriate to allocate QPCP costs to these customers as if they were firm.

Mr. Phillips explained that the revenue allocation method approved in the 2011 Rate Order is significant because the Commission's rule regarding the allocation of QPCP to classes clearly states that QPCP revenue requirement shall be allocated to classes based on the allocation parameters established in the last rate case. He stated that the Commission has never adopted a 100% energy allocation for fixed investment costs or associated revenue requirement, or a P&A method, for NIPSCO. He stated that the energy allocation methods recommended by Dr. Swan are completely at odds with the Commission's rule regarding the allocation of QPCP costs to classes.

Mr. Phillips testified the 2011 Rate Order did not approve a cost of service study or cost of service methodology. He noted that although the parties agreed to use the 12 CP demand allocators from NIPSCO's cost of service study for the RA Tracker, adjusted for interruptible load, and the RTO Tracker, the 12 CP method was not used for allocation or recovery of base rates costs.

Mr. Phillips testified that revenue requirement, which is cost responsibility by class, was established in the 2011 Rate Order (Joint Exhibit C to the Settlement). He stated that Dr. Swan apparently does not recognize the Joint Exhibit C revenue requirement responsibility allocation to classes as an appropriate allocation method but instead would substitute a 100% energy allocation or a 65% energy / 35% 4 CP method, which were never considered, for the actual allocation parameters used to establish revenue requirement by class and establish the rates currently in effect for electric service in NIPSCO's jurisdictional electric service territory.

Mr. Phillips disagreed with Dr. Swan that the Joint Exhibit E Allocation should be used as an alternative to his energy allocation. He stated that the 2011 Rate Order approved revenue requirement allocation is the actual allocation method or allocation parameter approved in NIPSCO's last general rate case and that no cost of service study was approved and no allocation method actually was endorsed or used to allocate costs that resulted in the rates approved by the 2011 Rate Order. He opined that it would be inconsistent to allocate the ECRM and fixed EERM costs differently from the costs in base rates.

Mr. Westerhausen testified in rebuttal that NIPSCO included ECRM factors based on the Joint Exhibit C Allocation in direct testimony because NIPSCO believes the base rate revenue requirement allocation is an equally appropriate allocation method. He testified that the Joint Exhibit C Allocation was approved as part of the 2011 Rate Order, NIPSCO's last base rate case, so it is consistent with 170 IAC 4-6-15.

Mr. Westerhausen testified that it would not be unreasonable to adjust the 12 CP allocators (Joint Exhibit E Allocation) for interruptible loads if 12 CP is used but he testified that it may be difficult to implement. Mr. Westerhausen explained that NIPSCO would need to separate interruptible customers (i.e., customers taking service under Rider 675) from non-interruptible customers in Rates 632, 633, and 634 prior to deducting the interruptible loads or else the non-interruptible Rate 632, 633, and 634 customers would benefit from deducting the interruptible load. He stated that the Joint Exhibit C Allocation (Base Rate Revenue Requirement Allocation) method would not require this adjustment for interruptible load and would be straightforward to administer.

With respect to Dr. Swan's recommendation to allocate ECRM costs either on the basis of energy use at generator or using the P&A method, Mr. Westerhausen testified that these options unnecessarily expand the playing field of alternatives considered for this filing. Mr. Westerhausen testified that these methods have never been used by the Commission for NIPSCO's ECRM rates. Furthermore, Mr. Westerhausen testified that the adoption of either the

Joint Exhibit C Allocation or the Joint Exhibit E Allocation would be consistent with the Commission's regulations addressing what allocation methodology should be utilized for purposes of allocating costs within the ECR filings (170 IAC 4-6-15).

170 IAC 4-6-15 states:

> A utility's jurisdictional revenue requirement that results from the ratemaking treatment of qualified pollution control property under construction under this rule shall be allocated among the utility's customer classes in accordance with the allocation parameters established by the commission in the utility's last general rate case.

The 2011 Settlement and 2011 Rate Order specifically left open the question of the appropriate allocation method for NIPSCO's ECRM and EERM factors. Accordingly, 170 IAC 4-6-15 provides no guidance with respect to the allocation ordered in Cause No. 43969 given the express language in the 2011 Rate Order that the allocation of QPCP would be determined based upon proposals presented in this Cause. Further, we do not believe that the negotiated revenue allocations that formed the basis of the 2011 Settlement should be applied to allocation of the ECRM revenue requirement in a contested case.

Instead, we find that our Order in Cause No. 43526 instructive. In that Cause, we determined that the 12 CP allocation was appropriate, and ordered NIPSCO to design its rates using that allocation. While rates under Cause No. 43526 never became effective, we should not ignore our allocation determination from less than two years ago. We note that the Commission did consider the P&A methodology in Cause No. 43526, and did not approve its use in that Cause, and we do not do so here.

Further, with respect to Mr. Phillips' recommendation to deduct interruptible load from the 12 CP allocations, we note that under NIPSCO's new rate structure, NIPSCO's tariffed rates generally provide for firm service, but industrial customers may seek credit for interruptiblity under Rider 675. The Commission's Order in Cause No. 43526, in the discussion following our finding that costs should be allocated based on 12 CP methodology, stated "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." The Commission sees no evidence to support a different conclusion for the environmental investment creating the costs discussed herein. Accordingly, we reject Mr. Phillips' recommendation to deduct interruptible load from the 12 CP allocations.

Based on the record evidence, we find that NIPSCO's ECRM factors should be allocated on the basis of Joint Exhibit E to the 2011 Settlement—the 12 CP method.

e. Reconciliation of Prior Period Recoveries. Mr. Westerhausen testified that Schedule 6 of Exhibit 1 shows the Company's reconciliation of projected period recoveries of ECRM revenue with actual revenue during the period from May 1, 2011 to October 31, 2011. He states, since the factors approved in Cause No. 42150 ECR 17 ended October 31, 2011, the

Company is able to compute any under or over recoveries of ECRM revenue, which are reflected in Column 6. He testified the projected and actual revenues were based on the 800 series rates and then mapped to the 600 series rates using the same methodology that was utilized in the December 21, 2011 compliance filing submitted to the Commission's Electricity Division following the 2011 Rate Order and are shown on Petitioners Exhibit No. CAW-1. Based on the record evidence we find that Petitioner properly included reconciliation in its ECRM calculations.

f. New ECRM Factors. Mr. Westerhausen sponsored Exhibit 2 (Rider 672 – Adjustment of Charges for Environmental Cost Recovery Mechanism) showing the ECRM factors applicable to the various NIPSCO rate schedules and explained how the ECRM factors were developed. Based on the record evidence, we find that the proposed ECRM factors set forth in Petitioner's Exhibit 2 were properly developed and should be implemented to be applicable to the bills of NIPSCO electric utility customers beginning May 1, 2012.

5. Commission Findings and Conclusions Regarding EERM.

a. Billing Period. Mr. Westerhausen testified that consistent with Rider 673 – Adjustment of Charges for Environmental Expense Recovery Mechanism, NIPSCO requests authority to recover operation, maintenance and depreciation expenses in connection with the operation of its QPCP that was in service during the twelve (12) months ended December 31, 2011 through its EERM to become effective May 1, 2012.

b. Actual O&M Expense. Mr. Titus testified that for the period ending December 31, 2011, NIPSCO incurred $18,660,965 of Actual O&M Expense, of which $2,215,844 was fixed and $16,445,122 was variable. He testified that the Actual O&M Expense consists of reasonably incurred O&M expenses associated with NIPSCO's ownership and operation of the QPCP facilities that have been placed in service. He stated that these expenses include the auxiliary power, chemicals and monitoring necessary to operate the QPCP. In addition, these expenses include the maintenance of the QPCP such as the chemical system, catalyst, soot blowers, controls, overfired air, low NOx burners and the balance of the facility. Mr. Titus testified that this is a $5,186,665 (38.5%) increase compared to 2010. The primary reason for this increase is an approximately $4.6 million increase in SCR chemicals, specifically the urea purchases. Upon the expiration of NIPSCO's long-term urea supply contract, NIPSCO procured urea on the open market at current market costs. Therefore, the cost of urea delivered to the site increased approximately 64% from 2010 costs. NIPSCO has contacted four vendors to discuss a long-term supply of urea. He also stated that currently, the Company is negotiating with one vendor who offered the most favorable terms.

In its April 16, 2012 responses to the Commission's April 12 Docket Entry, NIPSCO advised that its prior long term urea supply contract expired on April 10, 2011. NIPSCO made multiple attempts prior to the expiration of the contract to negotiate with the previous supplier to extend the previous contract. The previous supplier declined to participate in those discussions. NIPSCO followed its procurement procedures and invited various suppliers to discuss their company's pricing options to gather information about common pricing structures, delivery, and other charges to allow NIPSCO to develop a robust bidder list for a Request for Proposals

("RFP"). Through these discussions, NIPSCO learned that the most common pricing structure would be "market pricing" for urea with pricing variables for handling and delivery charges. NIPSCO developed an RFP which was sent out in February 2011 to obtain competitive pricing. Based upon this process a new provider was selected on March 15, 2011. NIPSCO did enter a supply contract with a new provider which was in place prior to the expiration of the former contract. This initial contract was for a one-year term, with an option to extend.

Based on the record evidence, we find that Petitioner's Actual O&M Expenses for the period ending December 31, 2011 of $18,660,965 are reasonable and should be included for recovery through the EERM factors beginning May 1, 2012. However, we would note that in future EERM proceedings, NIPSCO should provide more evidence to explain and support any significant increase in O&M Expense such as the 64% increase in urea costs included in this proceeding.

c. Actual Depreciation Expense. Petitioner's Exhibit 3, Schedule 1-EERM shows that NIPSCO's actual depreciation expense for the twelve months ending December 31, 2011 was $13,895,690. Mr. Plantz testified that the Actual Depreciation Expense consists of depreciation expenses incurred in the period January 1, 2011 through December 26, 2011 associated with NIPSCO's ownership and operation of the QPCP facilities that have been placed in service. He testified that the Commission's October 22, 2010 docket entry in Cause No. 43526 clarified that the effective date of new depreciation accrual rates authorized by the Commission in its 43526 Order "will coincide with the approval of new rates by the Electricity Division." Mr. Plantz testified that the new basic rates and charges proposed by NIPSCO in Cause No. 43526 had not been approved by the Commission; therefore, NIPSCO depreciated the QPCP projects using the same depreciation rates ordered by the Commission in Cause No. 38045, as required by the 42150 Order. Mr. Plantz explained that, as noted in the 2011 Rate Order, EERM factors are approved after the expenses have occurred and therefore, NIPSCO continued to defer the O&M and depreciation expenses related to the NOx and CAIR/CAMR projects that were added to rate base in Cause No. 43969, until the effective date of new electric rates (December 27, 2011). He testified that those deferred costs are reflected in this schedule. Specifically, this filing reflects costs incurred during the time period January 1, 2011 through December 26, 2011 for projects which are now in rate base as a result of the 2011 Rate Order. He further testified that this filing includes depreciation expense from the in-service date through December 31, 2011 for the NOx and CAIR/CAMR projects that went into service after June 30, 2010 and, therefore, are not in base rates.

Based on the record evidence, we find that Petitioner's Actual Depreciation Expense for the period ending December 31, 2011 of $13,895,690 are reasonable, and should be included for recovery through the EERM factors beginning May 1, 2012.

d. Net Emissions Allowance Expense. Mr. Plantz testified that the 43526 Order approved the tracking of emission allowance expenses and revenues in the EERM. Mr. Plantz testified that there were no purchases or sales of emission allowances in the reporting period.

e. <u>Allocation of Actual O&M and Depreciation Expenses</u>. Mr. Westerhausen 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.

For the reasons discussed above in Section 4(d), NIPSCO provided two alternate proposals for the production allocators used to develop its EERM factors. Mr. Westerhausen sponsored Schedule 1-EERM of Exhibit 1 which shows the production allocation percentages attributable to each of the Company's rate schedules based on the Joint Exhibit E Allocation. Mr. Westerhausen also sponsored Petitioner's Exhibit No. CAW-4, Schedule 1 which shows the Joint Exhibit C Allocation. Mr. Westerhausen testified that the energy allocators were updated utilizing test year sales for the twelve months ending June 30, 2010 from Cause No. 43969, adjusted for system losses.

Specific to the EERM factors, Dr. Swan testified that the Company has appropriately allocated the variable portion of the O&M component of EERM costs on energy. However, the OUCC recommends an allocation methodology on the basis of class energy at the generator for the allocation of depreciation and fixed O&M included in the EERM.

To support his allocation recommendation for the deprecation and fixed O&M included in the EERM, Dr. Swan testified the Company's proposal to allocate the depreciation portion of EERM costs and the fixed portion of the O&M component of EERM costs based on the Joint Exhibit E Allocation (12 CP) is incorrect and should instead be allocated 100 percent on energy because just as the QPCP and the return on this property are caused by the need to be able to produce energy with existing generation plant, so too is the depreciation of this plant and the fixed component of O&M caused by energy production and the need to reduce the associated emissions.

Dr. Swan testified that if the Commission is reluctant to adopt a 100 percent energy allocation of the fixed portion of these costs, the Commission should utilize a P&A allocator (based on 65 percent of class energy responsibility and 35 percent of class responsibility for the four summer peaks).

Dr. Swan testified the OUCC would be willing to accept the Company's proposed Joint Exhibit E Allocation (12 CP) of depreciation and fixed O&M as a compromise because that is the broadest standard coincident peak allocators. He stated that the Commission should reject any narrower coincident peak allocation of the EERM costs, such as a four summer peak allocation.

With respect to the EERM, Mr. Phillips stated that Dr. Swan proposed to change the long standing classification and allocation of depreciation expense and the fixed portion of O&M expense to variable expenses, which they are not. He stated that depreciation expense has been allocated on a demand allocation by NIPSCO for decades.

Mr. Westerhausen testified in rebuttal that he disagrees with Dr. Swan that NIPSCO is incorrectly allocating the depreciation portion of EERM costs and the fixed portion of the O&M component of EERM costs. Mr. Westerhausen testified it is reasonable to maintain a consistent treatment for the allocation of such costs on a going-forward basis compared to the allocation of such costs for all of the previous ECR filings. He stated NIPSCO has been allocating the depreciation and fixed O&M components inside of the EERM portion of the filings on the production allocation utilized for the capital costs inside of the ECRM. Mr. Westerhausen testified it would be appropriate to continue this methodology.

Based on the record evidence and the reasons supporting our conclusions in Section 4(d) above, we find that NIPSCO's ECRM factors should be allocated on the basis of Joint Exhibit E to the 2011 Settlement—the 12 CP method. We also find that NIPSCO should continue to allocate 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 Exhibit E Allocation or 12 CP. 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.

f. Reconciliation of Projected Period Recoveries. Mr. Westerhausen testified that Schedule 2-EERM of Exhibit 3 shows the Company's reconciliation of projected period recoveries of EERM revenue with actual revenue during the period from May 1, 2010 to April 30, 2011. He explained that since NIPSCO's EERM-7 factors ended April 30, 2011, the Company is able to compute any under or over recoveries of EERM revenue, which are reflected in Column 7. He further stated that the projected and actual revenues were based on the 800 series rates and then mapped to the 600 series rates using the same methodology that was utilized in the compliance filing submitted to the Commission's Electricity Division following the 2011 Rate Order and are shown on Petitioner's Exhibit No. CAW-3. Based on the record evidence, we find that Petitioner has properly included reconciliation in its EERM calculations.

g. New EERM Factors. Mr. Westerhausen provided testimony to explain how the EERM factors were calculated. Mr. Blakley testified that on Petitioner's Exhibit 3, Schedule 1-EERM, NIPSCO calculated its annual revenue requirement amount for its EERM to recover O&M and depreciation expense and that the total amount is netted against the prior period adjustment to arrive at $31,011,396.

Mr. Westerhausen sponsored Exhibit 4 (Rider 673 – Adjustment of Charges for Environmental Expense Recovery Mechanism) showing the EERM factors applicable to the various NIPSCO rate schedules and explained how the EERM factors were developed. Mr. Westerhausen also sponsored Petitioner's Exhibit 3, Schedule 1-EERM which shows that calculation underlying the proposed EERM factors. Based on the record evidence, we find that the proposed EERM factors set forth in Petitioner's Exhibit 3 were properly developed and should be implemented to be applicable to the bills of NIPSCO electric utility customers beginning May 1, 2012.

6. Commission Findings and Conclusions Regarding Progress Report. In its 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 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.

Pursuant to the ongoing review process under Ind. Code § 8-1-8.7-7, in this proceeding NIPSCO requests approval of its Ninth Progress Report on the status of QPCP tracked in the ECRM. Specifically, NIPSCO requests the Commission to approve its revised Compliance Plan as set forth in Exhibit 5 attached to the Company's Verified Petition initiating this Cause, including the updated project scopes, construction schedules, and cost estimates described therein.

The Commission approved NIPSCO's total CCT cost estimate of $518,862,005 ("Eighth Progress Report") in its ECR-17 Order. Since the Eighth Progress Report, NIPSCO has identified aspects of the plan that require further modification. Mr. Titus testified the plan modifications can be broken down into several categories: scheduling changes, scope additions, changes in estimated costs, changes due to the implementation of new base rates approved by the 2011 Rate Order, and the addition of the Phase I Projects and Phase II Projects approved in Cause No. 44012. The total estimated cost of the Compliance Plan presented by NIPSCO is $564,154,587. Therefore, as part of its Ninth Progress Report, NIPSCO is requesting approval of its updated QPCP cost estimate of $564,154,587.

Mr. Titus testified that Exhibit 5 attached to the Company's Verified Petition initiating this Cause identifies and describes three proposed scope additions to the NOx Compliance Plan and one proposed scope addition to the CAIR/CAMR Compliance Plan, including: (1) Unit 8 SCR Catalyst Layer 3; (2) Unit 12 SCR Catalyst Layer 4; (3) Unit 14 SCR Catalyst Layer 3; and (4) Unit 8 Decomposition Chamber Winterization.

Mr. Titus testified that the proposed revised total cost estimate for all Compliance Plan projects is $564,154,587. This total cost reflects: (1) decreases in cost estimates for the Unit 8 SCR Catalyst 2nd Layer, Unit 14 SCR Catalyst 2nd Layer, and Unit 7 SCR Catalyst 1st Layer; (2) estimated costs for four scope additions; (3) removal of projects that are now included in rate base as a result of the 2011 Rate Order; and (4) estimated costs for the Phase I Projects and (the then anticipated to be approved) Phase II Cause No. 44012 Projects

Based on the record evidence, we find that the Progress Report is reasonable and should be approved.

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

1. NIPSCO is hereby authorized to reflect the additional values of QPCP identified herein in its rates and charges for electric service in accordance with NIPSCO's ECRM.

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 reflect the rate adjustments reflecting the recovery of operation, maintenance and depreciation expenses identified herein in its rates and charges for electric service in accordance with NIPSCO's EERM.

4. Petitioner shall file with the Electricity Division of the Commission, prior to placing in effect the EERM 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.

5. Pursuant to Ind. Code § 8-1-8.7-7, NIPSCO's modified Compliance Plan, as described in NIPSCO's Exhibit 5 attached to the Petition is hereby approved.

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

ATTERHOLT, LANDIS, MAYS AND ZIEGNER CONCUR; BENNETT ABSENT:

APPROVED: MAY 02 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