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 8-1-2-6.8, 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 AND 44012; AND (2) MODIFICATIONS OF AND REVISED COST ESTIMATES RESPECTING CLEAN COAL TECHNOLOGY SET FORTH IN ITS TENTH PROGRESS REPORT PURSUANT TO THE ONGOING REVIEW PROCESS UNDER IND. CODE 8-1-8.7 AND APPROVED IN CAUSE NOS. 42150, 43188 AND 44012.	)	CAUSE NO. 42150 ECR 20 APPROVED: NOV 21 2012

<u>ORDER OF THE COMMISSION</u>

Presiding Officers:
Kari A.E. Bennett, Commissioner
Jeffery A. Earl, Administrative Law Judge

On August 1, 2012, Northern Indiana Public Service Company ("Petitioner" 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") factors to reflect costs incurred in connection with the construction of its Qualified Pollution Control Property ("QPCP"); (2) its Tenth 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, and 43913, and 44012 pursuant to Ind. Code ch. 8-1-8.7. NIPSCO prefiled the direct testimony of Ronald Plantz, Kurt W. Sangster, and Derric J. Isensee on August 1, 2012, and filed corrected schedules on August 24, 2012.

On August 28, 2012, the NIPSCO Industrial Group ("Industrial Group") filed its Petition to Intervene, which the Presiding Officers granted. On October 5, 2012, the Indiana Office of Utility Consumer Counselor ("OUCC") prefiled the direct testimony of Wes R. Blakley and Cynthia M. Armstrong. On October 10, 2012, NIPSCO prefiled the rebuttal testimony of Mr. Isensee and Mr. Sangster. The Industrial Group did not file evidence in this case.

Pursuant to notice given as provided by law, proof of which was incorporated into the record and placed in the official files of the Commission, an evidentiary hearing was held in this matter at 12:30 p.m. on October 15, 2012, in Hearing Room 224, 101 West Washington Street, Indianapolis, Indiana. At the hearing, NIPSCO and the OUCC presented their respective evidence, 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:

1. **Notice and Jurisdiction.** Proper legal notice of the hearing in this case was given and published by the Commission as required by law. NIPSCO is a public utility within the meaning of the Public Service Commission Act, as amended, Ind. Code ch. 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 NIPSCO and the subject matter of this case.

2. **NIPSCO's Characteristics and Generating System.** 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. **Background.** In the Final Order in Cause No. 42150 (the "42150 Order"), the Commission approved the following: (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 Environmental Expense Recovery Mechanism ("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").

In the final orders in Cause Nos. 42515, 42737, 42935, and 43144, the Commission approved revisions to NIPSCO's nitrogen oxide ("NO_x") Compliance Plan.

In the Final Order in Cause No. 43188, 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 ("SO_2"), ("NO_x") and Mercury ("Hg") emissions.

In the final orders in Cause Nos. 43371, 43593, and 43840, the Commission approved revisions to NIPSCO's NO_x Compliance Plan and CAIR/CAMR Compliance Plan (referred to collectively as the "Compliance Plan").

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

In the Final Order in Cause No. 42150 ECR 17 ("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 ch. 8-1-8.7 under the ongoing review process approved in Cause Nos. 42150, 43188, and 43913.

In the Phase I Order in Cause No. 44012 ("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 Unit 14 wet-FGD and Common Facilities (the "Phase I Projects"). The Phase I Projects are part of NIPSCO's Multi-Pollutant Compliance Plan ("MPCP"). The Commission approved NIPSCO's cost estimates for the Phase I Projects – $203 million for the Unit 14 FGD, $104 million for the Common Facilities, and $193 million for the Unit 15 FGD.

In the Phase II Order in Cause No. 44012 ("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 Selective Non-Catalytic Reduction ("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 NIPSCO'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 the Phase III Order in Cause No. 44012 ("Phase III 44012 Order"), the Commission approved NIPSCO's request for a CPCN for three CCT projects at NIPSCO's Michigan City Unit 12: (1) FGD Facility Addition; (2) Waterside Bypass SCR Reheat Project; and (3) Continuous Particulate Monitors Addition ("Phase III Projects"). The Phase III Projects are part of NIPSCO's MPCP. The Commission also approved NIPSCO's cost estimates for the Phase III Projects ($239,000,000 for the FGD Facility Addition; $7,017,700 for the Waterside Bypass SCR Reheat Project; and $375,000 for the Continuous Particulate Monitors Addition.)

In Cause No. 43969, NIPSCO sought approval of changes to its basic rates and charges for electric service. NIPSCO also requested the following: (1) 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-service at the end of the test year (the twelve months ended June 30, 2010) and that were being recovered through the ECRM; and (2) an adjustment of the ECRM to eliminate costs relating to those projects on the effective date of the new base rates and charges, subject to any necessary variance reconciliations. In the Final Order in Cause No. 43969 (the "2011 Rate Order"), the Commission approved a Stipulation and Settlement Agreement between NIPSCO, the OUCC, NLMK Indiana f/k/a Beta Steel Corporation, Indiana Municipal Utilities Group, and the 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 approved in the ECR 17 Order and the Final Order in Cause No. 42150 ECR 18 ("ECR 18 Order").

4. **Evidence Presented.**

(a) **Billing Period.** NIPSCO witness, 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 of NIPSCO electric utility customers in the months of November 2012 through April 2013. He stated the ECRM factors include actual costs through June 30, 2012, as well as a reconciliation of projected period recoveries of ECRM revenue with actual revenue during the period November 1, 2011, through April 30, 2012.

(b) **QPCP Investment.**

(i) **NIPSCO's Direct Testimony.** Mr. Isensee, testified the total cost of QPCP under construction, net of accumulated depreciation, upon which NIPSCO is authorized to earn a return is $227,130,690. 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. Mr. Isensee testified that if the Commission approves the proposed ratemaking treatment for the value shown in Schedule 1A of Exhibit 1 attached to NIPSCO's Verified Petition, NIPSCO will cease accruing AFUDC on those costs.

NIPSCO witness, Mr. Sangster, testified that Schedules 1 and 1A of Exhibit 1 attached to NIPSCO's Verified Petition describe the QPCP under construction on which NIPSCO proposes to earn a return. Schedules 1 and 1A 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 QPCP values for each project. The costs for the Company's QPCP projects have been compiled through June 30, 2012. Mr. Sangster 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 six months.

Mr. Sangster explained that NIPSCO updated the Schedules to incorporate the revised schedules and costs approved by the ECR 19 Order. Because NIPSCO anticipated that the Commission would issue a final order approving the Phase III Projects prior to the November 1, 2012 effective date of the new ECRM factors proposed in this proceeding, NIPSCO also updated Schedules 1 and 1A of Exhibit 1 attached to the Verified Petition to include the Phase III Projects.

(ii) **OUCC's Direct Testimony.** Cynthia Armstrong, Senior Utility Analyst, testified that the SCRs installed on Units 7, 8, 12, and 14 and NIPSCO's CAIR/CAMR Compliance Projects were added to rate base in Cause No. 43969. Ms. Armstrong explained that the catalyst layers and projects included in Schedule 1 are components of the main SCR and FGD projects that were approved in Cause Nos. 42150 and 43188 and are not "stand alone" pollution control projects that require special ratemaking treatment. The replacement of a catalyst layer within an SCR unit is similar to replacing boiler tubes or other maintenance projects done by electric utilities, which do not get special ratemaking treatment. The OUCC believes that a utility cannot continue to track the costs and value of the replacement or addition of catalyst layers of an SCR that is embedded in base rates without going through the process of a general rate case. Similarly, the utility cannot track replacements of boiler tubes, turbine blades, or additions of other general utility plant components that are included in rate base outside of a general rate case. The catalyst layers are capital maintenance, replacements, or upgrades for investments included in rate base. The related costs should not continue to be tracked through the ECRM, and any future maintenance activities related to these projects should also be removed from the tracking mechanism.

Ms. Armstrong stated that NIPSCO's continued tracking of these projects is contrary to the Commission's rules and previous orders. She pointed out that in Cause No. 43526, the Commission stated that these types of expenditures should no longer be tracked once they are added to rate base. She also noted that in Cause No. 43839 the Commission denied a proposal to track Variable Production Costs ("VPC"), which included chemicals and catalyst expenses associated with the operation of SCRs at Vectren South's generating facilities. She stressed that the Commission made it clear in these orders that pollution control equipment and any of its associated expenses that are embedded in base rates can no longer be tracked. She acknowledged that if NIPSCO experiences any increases in the level of expenses for operating or maintaining pollution control equipment, it can seek recovery of these expenses in a future rate case, consistent with 170 I.A.C. 4-6-22.

Ms. Armstrong further explained that the ongoing review provisions of Ind. Code §8-1-8.7-7(c) state that if the Commission approves the construction and the cost of the part of the CCT system under review, the approval forecloses subsequent challenges to the inclusion of that part of the CCT system in the utility's rate base on the basis of excessive cost, inadequate quality control, or inability to employ the technology. The OUCC does not question the inclusion of the catalyst layer costs because it considers these costs to be unreasonably excessive, unnecessary, due to NIPSCO's inability to adequately manage the project, or unable to deploy the project successfully. Rather, the OUCC questions the continued tracking of catalyst layer replacements and additions because the overall pollution control project, the SCRs, are already included in rate base. OUCC Witness Wes Blakley shows in his testimony that NIPSCO has an appropriate amount of capital value and expenses associated with the SCR already captured in rates.

Ms. Armstrong indicated that the ongoing review process contained in Ind. Code § 8-1-8.7-7 applies to pollution control projects that were initiated after a utility's last general rate case and are therefore not yet in rate base. She specified that under 170 I.A.C. 4-6-22, the tracking of the revenue requirements associated with these projects ceases once they are in service, deemed to be used and useful, and included in rate base through the utility's next rate case.

Mr. Wes Blakley, Senior Utility Analyst, provided additional support for the position that NIPSCO's base rates approved as a result of Cause No. 43969 include the costs of the SCRs for Units 7, 8, and 14, and the winterization of the decomposition chamber for the Unit 8 FGD. Because the SCR projects are complete and included in base rates along with prior catalyst layer costs, the new catalyst layer costs associated with these SCRs should not be tracked through the ECRM.

Mr. Blakley displayed the net original cost (or book value) of the SCRs as of June 30, 2010, which was approximately $214 million. Mr. Blakley explained that this figure is as of the end of the test year in NIPSCO's last rate case in Cause No. 43969. He compared this net original cost rate base value to the net original cost value of the SCRs as of August 31, 2012, which was approximately $198 million. The difference of $16 million is a decrease of the net original cost value of the SCRs. He further explained that NIPSCO's customers are paying base rates that reflect a larger net plant balance for these SCRs than what currently exists and that ratepayers cannot seek relief for this change in circumstances. He concluded that NIPSCO is requesting tracker recovery for catalyst layers for SCRs that are already in base rates, earning a return on and a return of the investment.

Mr. Blakley calculated a new revenue requirement for ECR-20 by removing the cost of the catalyst layers and winterization of the decomposition chamber ($4,166,766) to arrive at a new adjusted total project cost for ECR-20 of $222,963,924. He stated that the new adjusted semi-annual revenue requirement for ECR-20, including a prior period reconciliation of ($714,127), is $10,843,577.

(iii) **NIPSCO's Rebuttal Testimony.** Mr. Isensee testified that NIPSCO has properly included costs for the Catalyst Layer and Winterization Projects in the revenue requirement used to calculate the ECRM factors. Mr. Isensee believes that the OUCC's recommendation to remove the Catalyst Layer and Winterization Projects from NIPSCO's ECRM is inappropriate because the Catalyst Layer and Winterization Projects are stand-alone projects, NIPSCO received approval of these stand-alone projects pursuant to Indiana's CCT statutes, these projects are not included in NIPSCO's base rates, and Indiana's CCT statutes provide for timely recovery of these projects.

Mr. Isensee testified that the OUCC is challenging the inclusion of the following Catalyst Layer and Winterization Projects for recovery in NIPSCO's ECRM:

Nox Capital Projects	Replace/New	Approval Cause No.	Approval Date*
U8 SCR Catalyst 2nd Layer	Replacement	43840	7/7/2010
U14 SCR Catalyst 2nd Layer	Replacement	43840	7/7/2010
U12 SCR Catalyst 3rd Layer	Replacement	43840	7/7/2010
U7 SCR Catalyst 1st Layer	Replacement	42150-ECR 17	4/27/2011
U8 SCR Catalyst 3rd Layer	Replacement	42150-ECR 19	5/2/2012
U12 SCR Catalyst 4th Layer	New	42150-ECR 19	5/2/2012
U14 SCR Catalyst 3rd Layer	Replacement	42150-ECR 19	5/2/2012
CAIR/CAMR Capital Projects	**Replace/New**	**Cause No.**	**Approval Date***
U8 Decomp Enclosure	New	42150-ECR 19	5/2/2012

* Represents the date the Commission approved such projects as part of the respective progress report. The billing of the Company's current base rates and charges commenced on December 27, 2011, in accordance with the 2011 Rate Order.

Mr. Sangster testified that with the exception of the Unit 12 SCR Catalyst 4th Layer, all of the Catalyst Layer Projects are replacement layers—meaning that they are replacing an original catalyst layer in the SCR. The Unit 12 SCR Catalyst 4th Layer is an additional layer—not a replacement layer. These projects were approved by the Commission as part of NIPSCO's Seventh, Eighth, and Ninth Progress Reports in Cause Nos. 43840, 42150 ECR 17, and 42150 ECR 19, respectively. NIPSCO also included the Unit 8 SCR Decomposition Chamber Winterization ("Winterization Project"), which was approved by the Commission as part of NIPSCO's Ninth Progress Report in Cause No. 42150 ECR 19.

Mr. Sangster explained the purpose of the Catalyst Layer Projects and how they are differentiated from the SCR system as a whole. NIPSCO defines the catalyst layers as individual, complete layers of catalyst separated by elevation within the SCR. Each of the SCR systems was designed and built as a 3 + 1 system. The 3 + 1 system is a standard design within the electric utility industry and is defined as an SCR system that is originally loaded with 3 separate and distinct layers of catalyst with a fourth layer to be added at a later time as defined by the Catalyst Management Plan. The decision to use a 3 + 1 system instead of a 3 + 0 system was based on reducing the number of catalyst layer replacement events, and subsequently reducing the cost to rate payers. Knowing the original operating design basis and deactivation rate, NIPSCO can determine the number of catalyst layer replacement events and the net present value (NPV) for both reactor designs. In a 3 + 1 catalyst layer SCR system, the original three new catalyst layers are sufficient for operation of the SCR, however as the layers deactivate at different rates the fourth layer needs to be added. The layers are replaced and/or added per the Catalyst Management Plan due to the fact that over time, the SCR catalyst layers lose effectiveness and the ability to catalytically convert NO_x to nitrogen and water vapor. If not replaced, the SCR system would cease to function properly and become inoperable. The Catalyst Management Plan defines which layers are replaced at what frequency. NIPSCO's Catalyst Management Plan can be modified depending on the rate that catalyst layers are being used up or deactivated and the outage schedule.

Mr. Sangster also described the Winterization Project. The Winterization Project scope was building a new enclosure around the Unit 8 SCR Decomposition Chamber to protect the decomposition chamber's natural gas burner and instrumentation from freezing up during the winter months. The original decomposition chamber was designed to operate in winter weather conditions, however, during the winter of 2008 the system froze up and malfunctioned several times. The Decomposition Chamber uses natural gas to convert urea into ammonia to be used in the SCR to convert NO_x into nitrogen and water vapor. Without the Decomposition Chamber, the SCR cannot function. Therefore, a heated enclosure was built around the burner section of the Decomposition Chamber that included the instrumentation. He testified the Winterization Project helped increase the reliability of the generating unit and helped ensure that NIPSCO could continue to comply with environmental regulations.

Mr. Sangster stated that the Catalyst Layer and Winterization Projects are stand-alone projects and were approved for recovery on a stand-alone basis. NIPSCO maintains a separate and distinct work order to record capital expenses associated with each project, which allows the Company to place that asset in service separately. The Catalyst Layer and Winterization Projects have separate Commission-approved budgets. NIPSCO has regularly informed the Commission and its stakeholders about its ongoing efforts to replace and add catalyst layers. NIPSCO has discussed and requested approval of or revised cost estimates for eleven stand-alone catalyst layer projects (including the seven projects at issue in this ECR 20 filing) as part of its progress reports in Cause Nos. 43144, 43593, 43840, 42150 ECR 17, and 42150 ECR 19 -- all of which were presented as a stand-alone project with a separate and distinct cost estimate. Mr. Sangster said that the OUCC reviewed and addressed these projects in prior progress reports, and the Commission approved these projects, on a stand-alone basis.

In response to Ms. Armstrong's testimony, Mr. Isensee stated the language in the Commission's Final Order in Cause No. 43526, refers to O&M expenses for those units placed in rate base. Mr. Isensee said that the Catalyst Layer and Winterization Projects are currently being treated as capital projects—not O&M expenses. Secondly, all replacement layers currently included in base rates approved in Cause 43969, including the Unit 8 1st Layer, Unit 12 1st and 2nd Layers, and Unit 14 1st Layer, were treated as capital expenditures. Therefore, the current base rates reflect the recovery of these types of projects through depreciation expense in addition to the recovery of capital costs—not through O&M expense.

Mr. Sangster further explained why the Catalyst Layer Projects (both replacement and new 4th layer) are capital projects and not maintenance expense. Each catalyst layer is a distinct unit of property replaced in its entirety and each distinct unit of property has a useful life of between four and twelve years. Some of the original catalyst layers are being replaced with a larger pitch design which is an upgrade from the original design. This is not comparable to replacing boiler tubes or other maintenance projects done by electric utilities because in those examples, either the scope of work being replaced is not considered a distinct unit of property, it is not an upgrade from the original design, or the unit of property does not have a sufficient lifespan to define it as capital equipment.

Mr. Sangster testified that the Catalyst Layer Projects are not comparable to Vectren South Electric's proposal to track VPCs, which included chemicals and catalyst expenses, associated with the operation of SCRs that were included in base rates approved in Cause No. 43839 because catalyst layers are capital projects, not O&M.

Mr. Isensee testified that contrary to the OUCC's statements, NIPSCO has not included for recovery in this ECRM filing any projects that have already been included in base rates. The Catalyst Layer Projects and the Winterization Project were not in service at the end of the test year reflected in Cause No. 43969. Specifically, the Unit 8-2nd Layer, Unit 12-3rd Layer, and Unit 14-2nd Layer projects were approved in Cause No. 43840 on July 7, 2010, and the Unit 7 Catalyst 1st Layer was approved in Cause No. 42150 ECR 17 on April 27, 2011, but these projects were not in service at the end of the rate case test year. The Unit 8-3rd Layer, Unit 12-4th Layer, Unit 14-3rd Layer, and Unit 8 SCR Decomposition Chamber Winterization projects were approved in Cause No. 42150 ECR 19 on May 2, 2012, subject to approval of base rates in Cause No. 43969. By approving NIPSCO's Seventh, Eighth, and Ninth progress reports Cause Nos. 43840, 42150 ECR 17, and 42150 ECR 19, the Commission also authorized NIPSCO to recover the cost of the Catalyst Layer and Winterization Projects through its ECRM. Because the Catalyst Layer and Winterization Projects are distinct stand-alone projects, have separately approved budgets, and are not currently included in base rates, Mr. Isensee testified that it is appropriate to include them for recovery in NIPSCO's ECRM filings.

5. Commission Discussion and Findings.

(a) Catalyst Layer, Winterization Projects, and Total QPCP Investment. The evidence shows that the Catalyst Layer and Winterization Projects were not included in NIPSCO's base rates approved in Cause No. 43969. We also note that we approved these projects, including NIPSCO's ability to recover the approved costs, in Cause Nos. 43840, 42150 ECR 17, and 42150 ECR 19 pursuant to the ongoing review process set forth in Ind. Code § 8-1-8.7-7. NIPSCO has not changed its proposed treatment of or the estimated costs of these projects in this proceeding from what we approved in Cause No. 42150 ECR 19, and no party objected to the projects in that Cause. The evidence demonstrates that the Catalyst Layer and Winterization Projects are clean coal technology and are necessary to allow NIPSCO to comply with environmental regulations. We also find that NIPSCO's proposed treatment of these projects is not contrary to our Orders in Cause Nos. 43526 and 43839 because the issues in those Causes referenced by the OUCC concerned the continued tracking of O&M expenses, not capital expenditures. There is insufficient evidence in this Cause for us to reverse our prior findings regarding these Catalyst Layer and Winterization projects. Therefore, we find that NIPSCO's request to begin earning a return on $227,130,690, the value of its QPCP, net of accumulated depreciation, is reasonable and should be approved.

(b) Semi-Annual Revenue Requirement. NIPSCO requests approval of a Semi-Annual Revenue Requirement of $11,744,833 and an Adjusted Semi-Annual Revenue Requirement of $11,030,706 after adjusting for the prior period reconciliation.

Mr. Plantz computed NIPSCO's net semi-annual return on its QPCP as of June 30, 2012, to be $11,744,833, which includes a negative $28,864 adjustment for equipment transfer, which is the product of NIPSCO's QPCP value multiplied by its weighted cost of capital, adjusted for taxes and multiplied by 0.50. Revised Schedule 7 of Exhibit 1 shows that NIPSCO's Adjusted Semi-Annual Revenue Requirement is $11,030,706 after including the prior period reconciliation.

Mr. Plantz sponsored the calculation of NIPSCO's 6.85% weighted cost of capital, using its regulatory capital structure, per books, as of June 30, 2012, which is the date of valuation of the QPCP in accordance with 170 IAC 4-6-14. The cost rates for long-term debt and preferred stock reflect the 12 months ended June 30, 2012. 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.

Based on the record evidence, we find that NIPSCO's proposed Adjusted Semi-Annual Revenue Requirement of $11,030,706 is reasonable.

(c) Allocation of Semi-Annual QPCP Revenue Requirement. Mr. Isensee sponsored Revised Schedule 5 of Exhibit 1, which shows the production allocation percentages attributable to each of the Company's rate schedules. These allocation percentages were based on the production allocation percentages approved by the ECR 19 Order adjusted to reflect the significant migration of customers between Rates 624, 625, 626, and 632. We find that NIPSCO's ECRM factors have been allocated on the basis of the 12-CP method in accordance with our ECR 19 Order.[1]

(d) Reconciliation of Prior Period Recoveries. Mr. Isensee testified that Schedule 6 of Exhibit 1 attached to the Verified Petition shows the Company's reconciliation of projected period recoveries of ECRM revenue with actual revenue during the period from November 1, 2011, to April 30, 2012. Because the factors approved in Cause No. 42150 ECR 18 ended April 30, 2012, the Company is able to compute any under or over recoveries of ECRM revenue, which are reflected in Column 6. 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. We find that NIPSCO properly included reconciliation in its ECRM calculations.

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[1] We note that the May 2, 2012 Order in Cause 42150 ECR 19 and the August 15, 2012 Order on Reconsideration have been appealed by the NIPSCO Industrial Group and is pending before the Court of Appeals of Indiana in Cause No. 93A02-1205-EX-436.

(e) <u>**New ECRM Factors.**</u> Mr. Isensee 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 evidence and our discussion above, we find that the proposed ECRM factors set forth in Petitioner's Exhibit 2 were properly developed and should be implemented.

(f) <u>**Progress Report.**</u> In the 42150 Order, we approved NIPSCO's proposal that the Commission maintain an ongoing review of NIPSCO's QPCP construction and expenditures through an annual report of any revisions of the plan and cost estimates for such construction ("Progress Report"). In our Final Order in Cause No. 43526, we 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, in this proceeding NIPSCO requests approval of its Tenth 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 PR attached to the Verified Petition, including the updated project scopes, construction schedules, and cost estimates described therein.

We approved NIPSCO's total CCT cost estimate of $564,154,587 ("Ninth Progress Report") in the ECR 19 Order. Since the Ninth Progress Report, NIPSCO has identified aspects of the plan that require further modification. Mr. Sangster testified that Exhibit PR attached to the Verified Petition identifies and describes the plan modifications, which can be broken down into several categories: scheduling changes (Unit 15 SNCR Installation and Continuous Particulate Monitors Additions for Units 7, 8, 17, and 18); scope changes (Unit 14 SCR Reheat Project change from Duct Burners to Economizer Waterside Bypass); changes in estimated costs (Unit 14 SCR Reheat Project and Unit 15 SNCR); changes in the allocation of estimated costs between the three Schahfer FGD projects (Unit 14 FGD, Unit 15 FGD, and Common Facilities for Unit 14 & 15); and the addition of the Phase III Projects.

With respect to the proposed scope change for the Unit 14 SCR reheat project from Duct Burners to Economizer Waterside Bypass, Mr. Sangster testified that Economizer Waterside Bypass would allow NIPSCO to comply with regulatory requirements at a lower cost than Duct Burners. A Preliminary Engineering Study showed that waterside bypass technology will maintain the temperature of the SCR catalysts in Units 12 and 14 such that the SCR will operate during periods of expected low load. Through its internal technical review of the Preliminary Engineering Study, NIPSCO has determined that waterside bypass technology will be sufficient to comply with the NO_x limits imposed by the Consent Decree. The estimated cost to install waterside bypass technology at Unit 14 is $9,000,000 and Petitioner's Exhibit KWS-1 provides a breakdown of this order of magnitude cost estimate. The estimated annual O&M cost for waterside bypass technology at Unit 14 is $20,000. Mr. Sangster stated that these are insignificant compared to the annual O&M costs to support duct burners because water side bypass does not require fuel and there is less equipment to maintain. When compared to the capital cost of duct burners (estimated to be $16,000,000 for Unit 14) and the O&M expenses associated with duct burners (estimated to be $196,000 per year for Unit 14), NIPSCO believes waterside bypass technology is a more cost-effective SCR reheat technology for Unit 14. Based on this evidence, we find that installation of the

Economizer Waterside Bypass to remove NO_x emissions from Unit 14 will result in substantial cost savings in both the cost estimate and O&M expenses compared to the original Duct Burner project. Therefore, we find that NIPSCO's request to modify its CPCN to change the scope of the Unit 14 SCR reheat project from Duct Burners to Economizer Waterside Bypass and to change the cost estimate for the SCR reheat project to $9,000,000 is reasonable.

With respect to the change in estimated costs for the Unit 15 SNCR, Mr. Sangster testified that NIPSCO's Unit 15 SNCR Installation cost estimate has been revised from $6,000,000 to $6,400,000 to include boiler testing, which is required to complete the design engineering for the system, and additional installation costs required to maintain the project schedule due to alternate premium shiftwork required by weather and outage work. The total increase to the Unit 15 SNCR Installation cost estimate is $400,000 which is less than a 7% increase over the cost estimate approved in the 44012 Phase II Order. No party disputed this evidence. Based on our review of the evidence, we find that NIPSCO's request to modify its CPCN to change the cost estimate for the Unit 15 SNCR to $6,400,000 to reflect additional boiler testing and increased installation costs is reasonable.

Mr. Sangster testified that there are changes to the allocation of estimated costs between the three Schahfer FGD projects (Unit 14 FGD, Unit 15 FGD, and Common Facilities for Unit 14 & 15). He explained 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). However, as the engineering and construction have progressed, NIPSCO has identified that due to the technology selected and the application of internal accounting rules, more costs should be allocated to the "Common Facilities" work order and less costs should be allocated to the individual FGD work orders at Units 14 and 15. The Schahfer FGD project as a whole includes two hydroclone under flow tanks, two mist eliminator wash tanks and two filter belts. Originally, one of each of these pairs of equipment was assigned to the Unit 14 FGD and the other was assigned to the Unit 15 FGD. Upon selection of the vendor for the FGD technology and after consideration of options to improve reliability, each of these pieces of equipment was designed to operate with both Unit 14 and Unit 15 FGD systems. Therefore, the cost of each of these pieces of equipment was allocated to the Common Facilities rather than the Unit 14 and Unit 15 FGD facilities. As a result, NIPSCO is now projecting: (1) the Unit 14 FGD will cost $148,273,900—a decrease of $54,726,100 from the $203,000,000 cost estimate approved in the 44012 Phase I Order; (2) the Unit 15 FGD will cost $139,635,700—a decrease of $53,364,300 from the $193,000,000 cost estimate approved in the 44012 Phase I Order; and (3) the Common Facilities for Unit 14 & 15 will cost $212,090,400—an increase of $108,090,400 from the $104,000,000 cost estimate approved in the 44012 Phase I Order. These three changes net to zero and, as noted above, the total cost estimate remains $500 million. Therefore, we find that NIPSCO's request to modify its CPCN 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. The Commission also approves the continued inclusion of the SCR Catalyst Layer and Winterization projects as proposed by NIPSCO in its Progress Report for the reasons discussed in section (a) of our findings above.

The total estimated cost of the Compliance Plan presented by NIPSCO is $803,947,287. This represents an increase of $239,792,700 from the currently approved amount. However, $246,392,700 of the increase is due to the inclusion of the Phase III Projects (Unit 12 FGD--$239,000,000, Unit 12 Economizer Water Side Bypass--$7,017,700, and Unit 12 Continuous

Particulate Monitors--$375,000). Excluding the Phase III Projects, the revised total cost estimate represents a decrease of $6,600,000 from the currently approved amount. As part of its Tenth Progress Report, NIPSCO is requesting approval of its updated QPCP cost estimate of $803,947,287 and approval to recover these costs through the ECRM. NIPSCO's Tenth Progress Report also reflects and requests approval of NIPSCO's current estimate of the allocation of costs between the three Schahfer FGD projects which has a net zero impact on the total cost estimate. Based on the record evidence, we find that these CPCN modifications to change the cost estimate for NIPSCO's Compliance Plan are reasonable. We also find that the Tenth Progress Report is reasonable and the CPCN modifications to scope, schedule, and we approve the cost estimates contained therein.

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

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

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

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

APPROVED: NOV 21 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