ORIGINAL

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF DUKE ENERGY INDIANA, INC. SEEKING AUTHORITY TO REFLECT ADDITIONAL VALUES OF QUALIFIED POLLUTION CONTROL PROPERTY UNDER CONSTRUCTION IN ITS RATES THROUGH ITS STANDARD CONTRACT RIDER NO. 62, PURSUANT TO IND. CODE SECTIONS 8-1-2-6.6, 8-1-2-6.8 AND 170 I.A.C. 4-6-18; SEEKING APPROVAL OF AN ONGOING REVIEW PROGRESS REPORT CONCERNING CERTAIN CLEAN COAL TECHNOLOGY PROJECTS PURSUANT TO IND. CODE SECTION 8-1-8.7-7; SEEKING APPROVAL OF AN UPDATED COMPLIANCE PLAN, UPDATED COST ESTIMATES AND ESTIMATED IN-SERVICE DATES FOR ENVIRONMENTAL PROJECTS; SEEKING APPROVAL OF AN ADJUSTMENT TO ITS RATES THROUGH ITS CLEAN COAL OPERATING COST REVENUE ADJUSTMENT STANDARD CONTRACT RIDER NO. 71, IN ACCORDANCE WITH IND. CODE SECTION 8-1-8.8-11; AND SEEKING APPROVAL OF AN ADJUSTMENT TO ITS RATES THROUGH ITS SO_2, NOx AND Hg EMISSION ALLOWANCE ADJUSTMENT, STANDARD CONTRACT RIDER NO. 63	CAUSE NO. 42061 ECR 22 APPROVED: MAR 26 2014

ORDER OF THE COMMISSION

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

On October 28, 2013, Duke Energy Indiana, Inc. ("Petitioner," "Company" or "Duke Energy Indiana") filed a Petition with the Indiana Utility Regulatory Commission ("Commission") seeking: (1) to reflect additional values of qualified pollution control property ("QPCP") in its rates and charges for electric service through Standard Contract Rider No. 62 ("Rider 62"); (2) approval of an ongoing review progress report related to certain clean coal technology projects; (3) approval of an update and adjustment to Petitioner's Clean Coal Operating Cost Revenue Adjustment Mechanism, Standard Contract Rider No. 71 ("Rider 71"); (4) approval of updated environmental plan, cost estimates and estimated in-service dates for environmental projects; and (5) approval of an update and adjustment to Petitioner's sulfur dioxide ("SO_2"), nitrogen oxide ("NOx"), and mercury Emission Allowance Adjustment, Standard Contract Rider No. 63 ("Rider 63").

An Evidentiary Hearing was held on January 29, 2014 at 9:30 p.m. in Room 224, PNC Center, 101 West Washington Street, Indianapolis, Indiana. Petitioner and the Indiana Office of Utility Consumer Counselor ("OUCC") appeared at the hearing. Petitioner offered into evidence the testimony and exhibits of Mr. Joseph A. Miller, Jr., Ms. Diana L. Douglas, Mr. Joseph F. McCallister, and Mr. Charles E. Howell. The OUCC presented the testimony of Mr. Wes R. Blakley and Ms. Cynthia Armstrong. The evidence of both parties was admitted without objection.

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

1. Notice and Jurisdiction. Due, legal, and timely notice of the Evidentiary Hearing in this Cause was given and published by the Commission as required by law. Petitioner is a public utility as defined in Ind. Code § 8-1-2-1, and requests relief pursuant to Ind. Code §§ 8-1-2-6.6, 8-1-2-6.8, 8-1-2-42(a), Ind. Code chs. 8-1-8.7 and -8.8, and 170 IAC 4-6. The Commission has jurisdiction over Petitioner and the subject matter of this proceeding.

2. Petitioner's Characteristics. Petitioner is a public utility organized and existing under the laws of the State of Indiana, and has its principal office at 1000 East Main Street, Plainfield, Indiana 46168. It is engaged in rendering electric utility service in the State of Indiana and owns, operates, manages, and controls, among other things, plant and equipment within the State of Indiana used for the production, transmission, delivery and furnishing of such electric service to the public.

3. Petitioner's Electric Generating Properties. As of the date of the Petition in this proceeding, Petitioner's electric generating properties consist of: (1) two syngas/natural gas-fired combustion turbines and one steam turbine located at Edwardsport; (2) steam capacity located at four stations comprised of 14 coal-fired generating units; (3) combined cycle capacity located at one station comprised of three natural gas-fired combustion turbines ("CT") and two steam turbine-generators; (4) a run-of-river hydroelectric generation facility comprised of three units; and (5) peaking capacity consisting of seven oil-fired diesels located at two stations, seven oil-fired CT units located at two stations, and twenty-four natural gas-fired CTs, one of which has oil back-up.

4. Background to this Proceeding.

a. NOx SIP Call. The federal NOx State Implementation Plan ("SIP") Call and related Indiana NOx SIP Call required that Indiana reduce its NOx emissions during the ozone season of May 1 through September 30 to a level of 0.15 lb/mmBtu by May 31, 2004. The reductions in NOx emissions in Indiana came primarily from industrial and utility sources.

On July 3, 2002, the Commission issued an order in consolidated Cause Nos. 41744-S1 and 42061, wherein, among other things, we: (1) found that Petitioner's NOx Compliance Plan was reasonable; (2) issued a Certificate of Public Convenience and Necessity ("CPCN") for the use of clean coal technology; (3) approved the use of Petitioner's proposed QPCP; (4) approved Petitioner's updated cost estimates related to its NOx Compliance Plan equipment; and (5) approved Rider 62 that allows for construction work in progress ("CWIP") ratemaking treatment for Petitioner's QPCP. We found that Petitioner may update the value of its QPCP for CWIP ratemaking purposes no more often than every six months. Additionally, we found that, under our ongoing review rules, Petitioner should submit, at least annually, a progress report detailing any revisions in its cost estimates or in the planned construction of its NOx Compliance Plan projects.

b. CAIR and CAMR Compliance Requirements. In January 2004, the U.S. Environmental Protection Agency ("EPA") published two new significant proposed emission reduction requirements: (1) the Clean Air Interstate Rule ("CAIR"); and (2) the Clean Air Mercury Rule ("CAMR"). EPA finalized CAIR on May 12, 2005 (70 Fed. Reg. 25162) and CAMR on March 29, and May 18, 2005 (70 Fed. Reg. 15994 and 70 Fed. Reg. 28606).

The final CAIR requires major SO_2 and NOx emission reductions, established annual and seasonal NOx trading programs, and set limitations on use of SO_2 emission allowances. The Indiana Air Pollution Control Board adopted the final CAIR on November 1, 2006.[1] The final CAMR provides regulatory authority for a mercury cap and trade program, with a mercury cap for 2010 set at 38 tons, and 15 tons in 2018. The Indiana Air Pollution Control Board adopted the CAMR on October 3, 2007.[2]

On May 24, 2006, the Commission issued an order in consolidated Cause Nos. 42622 and 42718 approving a Settlement Agreement ("Settlement Agreement") among Petitioner, the OUCC, and the PSI Industrial Group wherein, among other things, it: (1) found that the Settlement Agreement was in the public interest; (2) approved Petitioner's Phase 1 CAIR/CAMR Compliance Plan; (3) found that the proposed scrubber, scrubber upgrade and baghouse projects constitute clean coal technology, clean coal and energy projects, and QPCP; (4) issued a CPCN for the Phase 1 CAIR/CAMR Compliance Plan projects; (5) approved Petitioner's request for ongoing review of the Phase 1 CAIR/CAMR Compliance Plan projects; (6) approved Petitioner's cost estimates for the Phase 1 CAIR/CAMR Compliance Plan projects; (7) approved the use of accelerated (20-year) depreciation for the Phase 1 CAIR/CAMR Compliance Plan projects as provided in the Settlement Agreement; and (8) approved the timely recovery of costs associated with Petitioner's CAIR/CAMR Compliance Plan.

c. Utility MATS Compliance Requirements. The EPA first proposed Maximum Achievable Control Technology ("MACT") standards for coal- and oil-fired utility steam generating units, known then as the Utility MACT rule, on May 3, 2011. In December 2011, the EPA signed the final rule, which was renamed the Mercury and Air Toxic Standards ("MATS"). The MATS rule became effective April 16, 2012.

The MATS rule regulates hazardous air pollutant emissions from new and existing coal- and oil-fired steam electric generating units that are greater than 25 MWs in capacity.

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[1] On July 11, 2008, the U.S. Court of Appeals for the D.C. Circuit in *State of North Carolina v. Environmental Protection Agency* issued an opiuiou vacating and remanding CAIR; however, parties to the litigation requested rehearing of aspects of the Court's decision, including the vacatur of the rules. On December 23, 2008, the D.C. Circuit granted rehearing only to the extent that it remanded the rules to EPA without vacating them. The ruling held that CAIR remaius in place until EPA issues a new rule in accordance with the July 11, 2008 decision ("CAIR Decision"). On July 6, 2011, the EPA finalized the Cross State Air Pollution Rule ("CSAPR"), with subsequent proposed revisions issued on October 6, 2011. On August 21, 2012, the D.C. Circuit Court vacated CSAPR in its entirety and directed EPA to continne administering CAIR pending completion of a valid replacement rule. On October 5, 2012, the EPA filed a petition seeking en banc rehearing of the D.C. Circuit Court's August 21, 2012 decision regarding CSAPR. On March 29, 2013, the Solicitor General, on behalf of EPA petitioned for a writ of certiorari with the U.S. Supreme Conrt to review the DC Circuit Court's August 21, 2012 decision. On June 24, 2013, the Supreme Court granted EPA's petition requesting review of the vacatur of the CSAPR.

[2] On February 8, 2008, the U.S. Court of Appeals for the D.C. Circuit, in *State of New Jersey, et al. v. Environmental Protection Agency,* vacated the Federal CAMR.

Specifically, it is a command and control program that imposes unit-by-unit restrictions on mercury, acid gases such as hydrogen chloride, and certain non-mercury metals such as arsenic, chromium, nickel and selenium. The MATS rule also requires sources to follow certain work practice standards designed to minimize emissions of organic materials and to minimize hazardous air pollutant emissions during periods of start-up and shutdown. The deadline for compliance is April 16, 2015.

With the new limits, conventional coal-fired units using bituminous or sub-bituminous coal, such as Duke Energy Indiana's generating units, will be subject to the "existing unit" limits of either 1.2 pounds of mercury emitted per trillion Btus of heat input or 0.013 pounds per gigawatt-hour of electricity generated.

On April 13, 2013, in Cause No. 44217, the Commission approved Phase 2 MATS Compliance Projects as QPCP eligible for CWIP ratemaking treatment in accordance with Ind. Code §§ 8-1-2-6.6 and -6.8, and as Clean Energy Projects qualifying for incentives in accordance with Ind. Code § 8-1-8.8-11.

d. Dry Sorbent Injection Projects at Gallagher Units 2 and 4. As part of the terms of a Consent Decree agreed to by Petitioner and the U.S. Department of Justice ("DOJ"), Petitioner agreed to install and operate dry sorbent injection ("DSI") systems on Gallagher Units 2 and 4 (the "Gallagher DSI Projects"). On September 8, 2010, in Cause No. 43873, the Commission granted a CPCN to Petitioner for the use of the Gallagher DSI Projects, approved the estimated costs for the projects, and found that the Gallagher DSI Projects constituted "Clean Coal Technology" as that term is defined in Ind. Code ch. 8-1-8.7. On December 28, 2011, in Cause No. 43956, the Commission granted Petitioner authority to include the Gallagher DSI Projects in its QPCP and to recover a return on the capital expenditures for the Gallagher DSI Projects through Rider 62 and to recover the incremental operation and maintenance ("O&M") expenses (including the cost of reagents and depreciation) of the Gallagher DSI Projects through Rider 71.

e. Emission Allowance ("EA") Adjustment. In Cause Nos. 42411 and 42359, the Commission approved the recovery of NOx EA costs in Petitioner's then-existing SO_2 Emission Allowance Adjustment mechanism. In Consolidated Cause Nos. 42622 and 42718, the Commission approved the inclusion of mercury EA costs in this same mechanism. Petitioner has used the Commission's 30-day filing process to implement these adjustments quarterly in accordance with the Settlement Agreement and Order in Cause No. 42411, but beginning with Cause No. 42061 ECR 10, elected to include future updates in the ECR proceedings.

5. Relief Sought in this Proceeding. In this six-month update proceeding, Petitioner requests the authority to reflect additional values of QPCP, as of June 30, 2013, in its rates and charges for electric service via Rider 62. Petitioner further requests approval of: (1) approval of an ongoing review progress report related to its NOx Compliance Plan, Phase 1 CAIR/CAMR Compliance Plan, Gallagher DSI Projects, and Phase 2 MATS Compliance Projects; (2) approval of recovery of Petitioner's O&M and depreciation expenses related to its NOx Compliance Plan, Phase 1 CAIR/CAMR Compliance Plan, Gallagher DSI Projects and capital maintenance environmental projects, including the reconciliation through June 30, 2013 and the estimated amounts related to its NOx Compliance Plan, Phase 1 CAIR/CAMR Compliance Plan, Gallagher DSI Projects, and capital maintenance environmental projects for the period July 1, 2013 through December 31, 2013 through Rider 71; (3) approval of

Petitioner's updated environmental plan, cost estimates and estimated in-service dates for the NOx Compliance Plan and Phase 1 CAIR/CAMR Compliance Plan projects; and (4) approval of an adjustment to its rates through Rider 63, including the reconciliation through August 2013 and Petitioner's estimated SO_2 and NOx emission allowance costs for March 2014 through August 2014.

6. **Statutory and Regulatory Framework.**

a. **Clean Coal Technology Statute.** Ind. Code § 8-1-8.7-7 provides that an applicant for a certificate of clean coal technology may elect ongoing review of its construction activities and construction costs, in which case the utility must periodically submit progress reports and cost estimate revisions to the Commission.

b. **CWIP Statute and Administrative Rules.** 170 IAC 4-6-4 provides that the Commission shall approve the use of QPCP if it consists of one or more air pollution control devices, the devices meet applicable state or federal requirements, the devices are designed to accommodate the burning of coal from the geological formation known as the Illinois basin, and the estimated costs of construction and installation are reasonable. Once pollution control equipment is found to be QPCP, then the utility is allowed to add the value of the QPCP to the value of the utility's property for ratemaking purposes. *See* 170 IAC 4-6-5; Ind. Code §§ 8-1-2-6.6, and 6.8. Per the Commission's CWIP rules, CWIP ratemaking treatment is available for QPCP that has been under construction for six months or longer, and a utility can update the amounts of its CWIP balances no more often than every six months. *See* 170 IAC 4-6-9 and -18.

c. **Utility Generation and Clean Coal Technology Statute.** Ind. Code § 8-1-8.8-11(a)(1) and (5) provide that "the commission shall encourage clean energy projects by creating the following financial incentives for clean energy projects, if the projects are found to be reasonable and necessary: (1) the timely recovery of costs incurred during construction and operation of projects described in section 2(1) or 2(2) of this chapter; . . . (5) other financial incentives the commission considers appropriate." Ind. Code § 8-1-8.8-2(1)(B) defines "clean energy projects" as "[p]rojects to provide advanced technologies that reduce regulated air emissions from existing energy generating plants that are fueled primarily by coal or gases from coal from the geologic formation known as the Illinois Basin, such as flue gas desulfurization and selective catalytic reduction equipment."

d. **Emission Allowauce Adjustment Authority.** Ind. Code § 8-1-2-42(a) contemplates and recognizes rate adjustments in accordance with tracking provisions approved by the Commission, specifically exempting such rate adjustments from Indiana's "fifteen month rule."

7. **Summary of Petitioner's Evidence.** Petitioner presented its case-in-chief testimony and exhibits of Mr. Joseph A. Miller, Jr., General Manager, Strategic Engineering, Duke Energy Business Services, LLC; Ms. Diana L. Douglas, Director, Rates, Duke Energy Business Services, LLC; Mr. Joseph F. McCallister, Director, Gas Oil and Power, Duke Energy Progress; and Mr. Charles E. Howell, Midwest Region Finance Manager for Power Generation Operations, Duke Energy Business Services, LLC.

a. **Compliance Plan Project Reports.** Mr. Miller stated that Petitioner is constructing its NOx Compliance Plan projects in order to comply with federal and state NOx

SIP Call regulations that took effect in May 2004 and is constructing its Phase 1 CAIR/CAMR Compliance Plan projects in order to comply with those federal requirements. Mr. Miller explained that Petitioner's NOx Compliance Plan is continuously changing and indicated that the current NOx Compliance Plan is not significantly different from the plan presented in Cause No. 42061 ECR 21 ("ECR 21"), the most recent six-month update case.

Additionally, Mr. Miller reiterated that the estimated costs of the NOx Compliance Plan have changed, but that the Company's cost estimates have been reasonably accurate. He explained that as with any multi-year plan there are ongoing impacts and refinements that could potentially affect costs. He indicated that changes in cost estimates generally reflect adjustments on the catalyst bed replacements planned for future years. He further added that with the Commission's approval, for CWIP ratemaking purposes, the Petitioner proposes to include the actual costs of the projects once they are known, whether higher or lower than the original estimates. Mr. Miller then testified that the NOx Compliance Plan cost estimates that were previously approved have increased due only to a change in the cash flow for the most recently completed selective catalytic reduction ("SCR") catalyst replacement project. Mr. Miller also mentioned the fact that although the NOx Compliance Plan projects are in-service,[3] that does not mean that additional construction dollars will not be spent or recorded on the project. He also testified that the Company has retired the original boiler optimization systems at Cayuga, Gallagher, and Wabash River Station.

Mr. Miller testified that the only projects added to the Phase 1 CAIR/CAMR Compliance Plan since the Settlement Agreement in Cause Nos. 42622/42718 have been the addition of mercury continuous emission monitors ("CEMS") that were under construction or purchased by the time CAMR was vacated. Mr. Miller testified that the mercury monitors at Gibson Station were either installed or almost completely installed at that time. The Company completed the installation of the Gibson Station monitors and one monitor at Gallagher Station, and placed the remainder of the purchased monitors in storage. Mr. Miller testified that in anticipation of pending MATS rules, the Company removed the Cayuga Station monitors from storage and installed those monitors in 2011. The Company is currently operating some of the already installed monitors at Gibson Station and Cayuga Station to learn more about how this equipment operates and to collect more data about the Company's actual mercury emissions from these units to help with compliance planning. The Company has also decided to continue to use the existing CEMS at Gibson and Cayuga to demonstrate compliance with the mercury limits under MATS once that rule becomes effective. The Company has had to make additional investments in the mercury CEMS at Cayuga in order to complete the installation and has had to replace the CEMS umbilical lines of several of the monitors and improve the heaters at Gibson, which have resulted in significant improvement in their reliability.

Mr. Miller explained that the mercury CEMS umbilical replacements at Gibson have been included in the capital maintenance projects presented by Mr. Howell and the costs to complete the Cayuga mercury CEMS installations are reflected in the Company's Phase 1 CAIR/CAMR Compliance Plan cost estimate update. He noted these costs were not previously presented to the Commission because the Company did not know if it would ultimately proceed with long-term operation of the mercury CEMS until there was more certainty around replacement to the vacated CAMR. Now that the Company knows it will continue to operate

[3] "In-service" means the equipment has been installed and is in operation.

and maintain the mercury CEMS at Cayuga and Gibson for MATS mercury compliance, it is including those investment costs in this proceeding.

With regard to the mercury monitors at the Gallagher Station, Mr. Miller testified that the Company completed installation of one mercury CEM and incurred preliminary costs in preparation to install the second (prior to the vacatur of CAMR). Referencing his testimony in Cause No. 44418, he stated Gallagher Station will comply with the MATS mercury limits without further investment in environmental control equipment. He said the Company determined that mercury sorbent traps were a better option for demonstrating mercury compliance at Gallagher Station by evaluating the capital costs associated with completing the installation and certification of the mercury CEMS, along with the estimated O&M costs associated with maintaining two continuously operating mercury CEMS, and compared those costs with the costs of completing these projects with mercury sorbent trap device technology instead. The mercury sorbent trap estimates are near the previously approved estimates for the mercury monitors and project an O&M savings of $50,000/year. Therefore, Petitioner plans to install two mercury sorbent traps at Gallagher Station rather than complete or reinstall the mercury CEMS.

Mr. Miller explained the Company proposes the costs for the Gallagher A stack mercury sorbent trap installation be a capital maintenance project related to the existing A stack mercury monitor project and that the incremental costs for the B stack mercury sorbent trap installation would be applied to the original project estimate for the existing mercury monitor project that was not previously placed into service. These projects would be completed by April 1, 2015, but have not yet been done, thus no changes were made to exhibits in this proceeding. With Commission approval of these changes to the plan, future ECR proceedings will provide an update as the activities take place.

Mr. Miller described the emissions benefits associated with the Gallagher baghouses. He explained that the baghouses resulted in significant decreases in emission rates of filterable particulate matter ("PM"), mercury, and SO_2. The baghouses and DSI systems also enable Gallagher Station to comply with the MATS filterable PM and acid gas emission limits. The Company is evaluating some stack improvements to improve the safety and efficiency of quarterly stack testing of filterable PM and hydrogen chloride, and if needed, the improvements would be implemented in concert with the completion of the Gallagher Station mercury monitor projects.

Mr. Miller discussed Petitioner's updated cost estimates for the Phase 1 CAIR/CAMR Compliance Plan projects. He explained that as with any multi-year plan, there are incremental changes from ongoing impacts and refinements to the projects as a normal part of an ongoing construction program. He added that Petitioner expects these costs to continue to be refined to a small degree. Overall, Petitioner's estimated costs for its Phase 1 CAIR/CAMR Compliance Plan have increased slightly.

Mr. Miller indicated that Petitioner proposed, for CWIP ratemaking purposes, to include only the actual costs of the projects once they become known, whether those costs are higher or lower than the original estimate on any specific project. He stated he believes the current cost estimates of Petitioner's CAIR/CAMR Compliance Plan continue to be reasonable.

Mr. Miller discussed the status of the Gallagher DSI Projects that were part of the Consent Decree reached with the DOJ. The Company received a CPCN to install and operate the Gallagher DSI Projects from the Commission in Cause No. 43873. The Commission also granted the Company authority in Cause No. 43956 to recover costs associated with the installation and operation of the Gallagher DSI Projects through its environmental cost recovery rider.

Mr. Miller provided the Company's 2013 annual progress report on the Gallagher DSI Projects stating that construction and testing of both DSI systems on Units 2 and 4 were substantially complete in 2010 and that Duke Energy Indiana has been able to maintain the required sulfur limits. Mr. Miller further stated that the cost estimates of the DSI Projects, since the Company's last progress report, remain the same and that the Company is continuing to evaluate the need of whether ash fixation in the landfill is necessary as a result of operating the DSI systems.

Next, Mr. Miller noted that the reasons why Petitioner is constructing Phase 2 MATS Compliance Projects was discussed in Cause No. 44217. He explained that the Company must further reduce the mercury emissions from its generating facilities in order to comply with the MATS rule and its anticipated compliance date of April 16, 2015, and that the primary focus of the plan is reducing the mercury emissions at Cayuga and Gibson stations. He noted the Company has recently filed, in Cause No. 44418, its Phase 3 compliance plan seeking approval of remaining investments needed to ensure and demonstrate compliance with MATS limits, mainly at Gibson Station.

Mr. Miller described the Company's current Phase 2 MATS Compliance Plan in Petitioner's Exhibit A-3. He explained that in the Company's Phase 3 environmental compliance filing, the Company proposed to withdraw its previous request made in its Phase 2 plan to install activated carbon injection ("ACI") at Gibson Unit 5 and to replace the ACI with a calcium bromide injection system in order to save both capital and O&M costs. In addition, Mr. Miller testified that the Company intends to defer installation of the ACI projects previously approved for Cayuga pending additional mercury emission testing after the SCRs are operational and will provide an update in future ECR proceedings.

Noting that Petitioner is awaiting an Order in Cause No. 44418, Mr. Miller testified that the estimated costs of the Phase 2 MATS Compliance Plan have not changed and that the Company believes the projects will be completed on time and within the approved cost estimate. However as with any multi-year plan, he would expect minor changes from ongoing impacts and refinements to the projects as a normal part of an ongoing construction program.

Mr. Miller explained the status of construction at Cayuga as of the end of June 2013: the SCR equipment vendor was 99% complete; fabrication on Unit 1 was complete; and Unit 2 fabrication was 32% complete. The ammonia system fabrication was complete and delivery was being coordinated. The general works contractor was mobilized on site. Structural steel fabrication and steel and ductwork deliveries continued and the structural steel erection of the SCR tier 1 support steel had also began. Engineering on the Cayuga sorbent projects was underway. All major equipment contracts for the Cayuga SCR projects and sorbent projects have been awarded, and no contracts have yet been awarded for the Gibson or Cayuga Station mercury re-emission chemical systems. Approximately $124 million in contracts associated with the Phase 2 MATS Compliance Plan projects have gone to Indiana-based contractors, and that site mobilization began in May 2013. He stated that no construction activities were underway yet at Gibson Station.

b. **<u>Rider 62</u>.** Ms. Douglas described the proposed implementation of CWIP ratemaking treatment via Rider 62 and provided the schedules and information required by 170 IAC 4-6-12. Specifically, Ms. Douglas provided information establishing the incremental value of QPCP investment through June 30, 2013 for approved NOx Compliance Plan, Phase 1 CAIR/CAMR Compliance Plan, and related capital maintenance projects, as well as for the Gallagher DSI and Phase 2 MATS Compliance Projects for which Petitioner is seeking recovery; showed the computation of the jurisdictional revenue requirement associated with that investment; and determined the allocation of the jurisdictional revenue requirement to various retail customer groups. Ms. Douglas explained that consistent with the Commission's Order in consolidated Cause Nos. 41744-S1 and 42061 and subsequent related Orders, the QPCP projects will be deemed to be under construction, and Petitioner will continue to receive revenues through Rider 62, until the Commission determines that these projects are used and useful in a proceeding that involves the establishment or investigation of Petitioner's base rates and charges, or until these projects no longer satisfy the other requirements of the Commission's CWIP ratemaking rules.

Ms. Douglas testified regarding how retirements have been accounted for on the Company's accounting books and records pursuant to U.S. Generally Accepted Accounting Principles. The retirements reflected in this filing are all considered normal retirements. In addition, she explained that depreciation of an asset on the accounting books stops upon retirement. The Company has appropriately reflected this in the actual and estimated depreciation amounts included in this filing, as appropriate based on the dates the equipment was retired.

Ms. Douglas explained the costs associated with capital maintenance projects affiliated with the approved NOx Compliance Plan and Phase 1 CAIR/CAMR Compliance Plan projects, which were approved by the Commission in Cause No. 42061 ECR 18 for recovery in Riders 62 and 71.

Ms. Douglas described the term capital maintenance, how the Company classifies its property pursuant to the Federal Energy Regulatory Commission ("FERC") Uniform System of Accounts, and how the Company determines whether something is a property unit that must be capitalized.

Mr. Howell discussed the capital maintenance projects for which costs, incurred after June 30, 2011, have been included. Mr. Howell explained that all of the projects are in service as of the June 30, 2013 cutoff for this filing, except for the Gibson 1-5 Ammonia Delivery System, related to QPCP under the approved NOx Compliance Plan and Phase 1 CAIR/CAMR Compliance Plan for which Petitioner seeks recovery:

Project	NOx or Phase 1 QPCP	Completion Status
Cayuga 1 Absorber Recirculating Pump Motor Rewind	FGD[4]	In Service
Gallagher 2 Baghouse Bag Replacement	Baghouse	In Service
Gibson 1-5 Soda Ash Pumps	SCR	In Service
Soda Ash Tank Platform/Vent/Insulation	SCR	In Service
Gibson 3 SCR SBS probes	SCR	In Service
Gibson 1-3 FGD Service Water Strainer	FGD	In Service
Gibson 1 SCR NOx Monitor Control System	SCR	In Service
Gibson 5 SCR NOx Monitor Control System	SCR	In Service
Gibson 1 B2 SCR Dilution Air Fan Motor	SCR	In Service
Gibson 1-5 Ammonia Delivery System	SCR	In Progress
Gibson 1-5 Reagent Air Receiver Tank	FGD	In Service
Cayuga 2 FGD EJ6 and EJ7 Replacement	FGD	In Service
Gibson 2 SCR Turning Vanes	SCR	In Service
Gibson 1-5 Absorber Recirculating Pump Motor Rewind	FGD	In Service
Gibson 1-3 Reactive Prep Sump Pump	FGD	In Service
Gibson 3 Ball Mill Liner	FGD	In Service
Gibson 2 Ball Mill Liner	FGD	In Service
Gibson 1-3 FGD Oxidation Air Humidity Water Source	FGD	In Service
Gibson 1 Ball Mill Liner	FGD	In Service
Gibson A Absorber Area Sump Pump	FGD	In Service
Gibson 3 Mercury CEMS Umbilical	FGD	In Service
Gibson 5 Mercury CEMS Umbilical	FGD	In Service
Gibson 1-3 Air Compressor	FGD	In Service
Gibson SBS Reagent Air Compressor	FGD	In Service

Additionally, Mr. Howell testified about other future maintenance projects, such as the replacement of the absorber piping, gearboxes, and ball mill liners on FGD equipment at Gibson Station. In addition, the Company has plans to install improved mercury sample probes at Gibson, continue to upgrade the mercury CEM umbilicals, and install a mercury CEMS nitrogen generator, which are all CEMS-related projects needed to maintain the reliability and accuracy of the mercury CEMS.

Ms. Douglas explained the inclusion of costs associated with the Gallagher DSI Projects, and the Phase 2 MATS Compliance Projects, and that were discussed further by Mr. Miller.

Ms. Douglas explained the amount of accumulated depreciation as of June 30, 2013 that is applicable to the investment for projects under the NOx Compliance and Phase 1 CAIR/CAMR Plans and their related capital maintenance projects, as well as for the Gallagher

[4] Flue Gas Desulfurization.

DSI Projects. She also explained how the retirement of Gallagher Units 1 and 3 in January 2012 have been reflected.

Ms. Douglas testified that the federal income tax rate used in the calculation of the jurisdictional revenue requirement was not adjusted to reflect a tax deduction under the Internal Revenue Code Section 199 provided for in the American Jobs Creation Act of 2004 because the Company will not be allowed to take the deduction (when the factors developed in this filing will be billed to customers) due to its expected tax position after reflecting bonus depreciation for Edwardsport's Integrated Gasification Combined Cycle ("IGCC") plant.

Ms. Douglas also explained that Petitioner pledged to return the difference between the property tax expense approved in Cause No. 42359 and actual jurisdictional property tax expense, if lower. Ms. Douglas testified that based on this commitment there is currently estimated a $252,000 over-refunded amount via Riders 62 and 71 through August 2013 and that the Company proposes for administrative convenience that the final reconciliation for tax years 2010-pay-2011 and 2011-pay-2012 expense be made in Rider 71 rates to effectuate a full property tax reconciliation via ECR 22 billings. She stated that the Company will continue to report the estimated and final amounts in Rider 62 testimony until the 2012-pay-2013 tax year amounts are final and that if the final amounts are ultimately more than the amount in base rates, the Company will discontinue tracking property taxes in Rider 62 in accordance with the testimony and Order in Cause No. 42359.

Ms. Douglas testified regarding the jurisdictional revenue requirement for CWIP, net of a $7,572,000 annual credit (which continues until new base rates become effective) for the jurisdictional net savings associated with the differential between the costs included in rates for Wabash River Unit 1 and Wheatland Plant costs, in accordance with the Commission's Order in Cause Nos. 42908 and 43211, approving the sale of Wabash River Unit 1 to Wabash Valley Power Association.

c. Rider 71. Ms. Douglas also explained and supported Petitioner's proposed adjustments to Rider 71 covering the reconciliation of depreciation and O&M expenses billed versus depreciation and O&M expenses actually incurred for the six months ended June 30, 2013, and the estimated costs for the period July through December 2013. Ms. Douglas also testified that the Company is requesting the continued recovery of amortization of Phase 2 MATS Compliance costs over a three-year period, as presented and approved for recovery in Cause No. 42061 ECR 21. The Company is also requesting to include the final property tax reconciliation amount of $252,000 in Rider 71. Ms. Douglas stated the Company was also including a credit to customers in the amount of incremental demand revenues under a contract with Nucor Corporation (the "Nucor Credit"). Ms. Douglas explained the inclusion of a similar credit under a contract with International Paper.[5] Ms. Douglas further explained the proposed revenue requirement recovery amount resulting from the estimated jurisdictional O&M and depreciation expenses expected to be incurred for the six months ended December 31, 2013, the revenue requirement resulting from estimated jurisdictional depreciation expenses, amortization of the retail jurisdictional portion of Phase 2 MATS Compliance costs, and the reconciliation amount for the six months ended June 30, 2013.

[5] Formerly known as Temple-Inland.

Mr. Howell testified that the projects having incremental O&M expenses associated with the Company's NOx Compliance Plan are the Gibson Station Units 1-5 SCRs, Gibson Station Units 1-5 arsenic mitigation system, and the Gibson Station Units 1-5 SO_3 mitigation systems. He stated that these incremental costs will fluctuate based on demand and the generation level of the units. Mr. Howell also testified regarding the incremental O&M expenses associated with the Company's Phase 1 CAIR/CAMR Compliance Plan. He explained that the projects associated with these expenses are the Cayuga Units 1 and 2 FGDs, Gibson Station Units 1-3 FGDs, Gibson Station Units 4 and 5 FGD upgrades, and Gallagher Units 1-4 baghouses. He concluded that the incremental costs associated with these projects will also vary based on demand and the generation level of the units. Finally, Mr. Howell explained the incremental O&M expenses associated with the Gallagher DSI Projects. Again, he concluded the incremental costs associated with these projects are not fixed and will vary based on demand and the generation level of the units.

Ms. Douglas explained that pursuant to the Consent Decree entered into by the Company and the DOJ resolving New Source Review litigation, the Company retired Gallagher Units 1 and 3 at the end of January 2012. She explained that the Commission's December 28, 2011 Order in Cause No. 43956 approves the amortization and recovery of the net book value of these units over 14 years. As such, the estimated depreciation expense for the Gallagher DSI Projects, which are included in Riders 62 and 71, has been reflected using a 14-year amortization rather than using the approved accelerated depreciation rates that had been previously used for the NOx Compliance Plan and the Phase 1 CAIR/CAMR Compliance Plan projects.

Ms. Douglas further explained that both the Company's capital maintenance projects and Gallagher DSI Projects are being depreciated using the Commission-approved depreciation rates in Cause No. 43114 IGCC 4S1 ("IGCC 4S1 Order") based on the FERC accounts associated with the property. She stated that the IGCC 4S1 Order also approved a Settlement Agreement provision that allowed the Company to continue to use the accelerated rates previously approved by the Commission for the NOx Compliance Plan and Phase 1 CAIR/CAMR Plan projects for purposes of Riders 62 and 71 recovery, while also approving the use of non-accelerated depreciation rates for book accounting purposes until the next base rate case. Ms. Douglas testified that depreciation has been adjusted, as appropriate, for retirements.

Next, Ms. Douglas described the conversion of O&M, depreciation, and Phase 2 MATS Compliance plan development costs to revenue requirements. She testified that depreciation expense was separated into two components before converting to revenue requirements: (1) the portion related to equity Allowance for Funds Used During Construction ("AFUDC"), and (2) the portion related to all other costs comprising the investment being depreciated.[6] The portion of depreciation expense applicable to equity AFUDC costs was converted to revenue requirements using a calculation that includes a provision for both state and federal income taxes, and the remainder of the depreciation expense was converted to revenue requirements using the same revenue conversion factor as for O&M and the Phase 2 MATS Compliance plan development costs. She explained that under current income tax regulations, the equity AFUDC component of depreciation expense is not a deductible item when computing income taxes; therefore, utility revenues representing the recovery of the equity AFUDC component of depreciation expense are not offset by a deductible expense item. This is the same reason that the revenue requirement for the equity component of return includes a provision for state and

[6] This includes direct costs and debt AFUDC.

federal income taxes. Ms. Douglas said that without a provision for income taxes in the revenue conversion factor for the equity AFUDC component of depreciation expense for new assets placed in service after base rates were established, the utility will not fully recover its costs. She explained that in this proceeding, application of these different revenue conversion factors to separate equity AFUDC and all other components of depreciation expense allows the Company to fully recover its costs for income taxes for tracked plant. Ms. Douglas testified that this method was first used by the Company in Cause No. 43114 IGCC 10 to calculate the revenue requirements associated with depreciation expense, which was approved by the Commission on September 11, 2013.

Finally, Ms. Douglas explained that a credit for the amount of Nucor demand revenues apportioned to Riders 61, 62, and 71, representing the apportioned amount of 2014 demand revenues applicable to Nucor's interruptible load, and a reconciliation of the credit applicable to January through June 2013 was included in the development of the revenue requirement used in developing the Clean Coal Operating Cost Revenue Adjustment Factors. The Nucor Credit was calculated in accordance with the Commission's Order in Cause No. 43754 and its Order in Cause No. 42061 ECR 15 ("ECR 15 Order") using the revenue requirements proposed in this proceeding for both Rider 62 and Rider 71 (excluding the Nucor Credit and International Paper Credit) and the revenue requirements from the most recently approved Rider 61 (Cause No. 43114 IGCC 10). Ms. Douglas testified that the International Paper Credit was calculated in accordance with the Commission's Order in Cause No. 44087 and its ECR 15 Order (related to the Nucor credit) using actual steam demand for the period January through June 2013 and the revenue requirements proposed in this proceeding for Riders 62 and 71 (excluding the Nucor Credit and International Paper Credit).[7] She noted this is the first time a reconciliation has been required for the International Paper Credit. She further explained that Petitioner planned to include credits representing six months' worth of apportioned Nucor and International Paper demand revenues in future ECR proceedings until such time as Nucor and International Paper demand revenues have been included in new base rates approved by the Commission in Petitioner's next retail base rate case.

d. **<u>Rider 63</u>.** Ms. Douglas explained and supported Petitioner's proposed adjustments to Rider No. 63, covering the reconciliation of SO_2 and NOx net EA expenses billed versus the net expenses incurred for the six months ended August, 2013, and the estimated NOx and SO_2 EA costs for the period March through August 2014.

Ms. Douglas testified that a proposed factor of $0.000260 per kWH is being requested for the March through August 2014 billing period. She testified that this factor includes realized gains and losses from the sale of SO_2 and annual NOx emission allowances. She further testified that no estimates were included of EA sales during the projected period.

Mr. McCallister testified that there continues to be uncertainty regarding the timing of potential implementation of CSAPR or its replacement and that it is currently anticipated that CAIR will be in effect for 2013 and 2014 EA compliance. He also explained the vacature and current status of CSAPR impact on the CAIR programs, CAIR allowances in inventory, and compliance. He stated that in October 2012, EPA returned the vintage 2013 CAIR annual and seasonal NOx allowances because CAIR is anticipated to remain in place with the 2013 seasonal and annual NOx requirements. EPA also allocated 2014 annual and seasonal NOx allowances.

[7] Rider 61 is not applicable to the International Paper steam contract.

Mr. McCallister further explained that while CAIR is in effect, SO_2 compliance will take place using the compliance ratio mandated by CAIR, which ratio is increasing.

Mr. McCallister summarized that given the vacature of CSAPR and assuming CAIR is in place for the 2013 and 2014 compliance period, the Company will have to comply with the requirements of CAIR annual NOx, CAIR seasonal NOx, and Title IV/Acid Rain SO_2 using the CAIR SO_2 ratio requirements.

Mr. McCallister described the trading market for CAIR EAs. He stated that since the vacature of CSAPR in August 2012, market activity for CAIR allowances continues to be limited. Based on recent market activity, 2013 CAIR SO_2 EAs are trading at approximately \$0.65/EA, 2013 CAIR annual NOx EAs are trading at approximately \$39/EA, and 2013 CAIR seasonal NOx EAs are priced at approximately \$21/EA.

Mr. McCallister further testified that since the vacature of CSAPR, there was no compliance need for vintage 2012 CSAPR EAs and observable market activity has been very limited. He went on to state that the Company has not observed any CSAPR EA market activity in 2013.

Mr. McCallister described the types of transactions that occur in the EA market and why it is necessary for Duke Energy Indiana to participate. Mr. McCallister described the sophisticated production costing model that Petitioner uses to determine whether the Company needs to purchase EAs or if the Company has a surplus and can sell some of its EA inventory. According to Mr. McCallister, the model recognizes and reflects the interrelationship and interaction of the various inputs, such as capacity, fuel type, heat rate, forced outage rates, and emission rates. Mr. McCallister explained that Petitioner strives to meet its native load customers' energy requirements by purchasing energy from the wholesale power market when such purchases are more economic than running Duke Energy Indiana's own generating units. Mr. McCallister stated that the model is just a tool, and that judgment must be applied to the output. He explained that the model distinguishes between native load EA requirements and EAs to support non-native sales, and that the inventories are managed separately. He stated that once a purchase is made for native load, those EAs remain with native load, and similarly for purchases made for non-native load. In addition, all zero cost allowances that the Company receives are maintained for the benefit of native load customers.

Mr. McCallister explained that Petitioner's goal is to approach a balanced position after considering allocations provided by EPA, existing inventory and emission usage based on forecasting and actual usage. In addition, because EAs that do not have to be surrendered to the EPA are valid in later years, Petitioner must also consider the Company's position in later years.

Mr. McCallister described the Company's current positions in regard to CAIR SO_2 and seasonal and annual NOx EAs stating that the Company projects it will have more allowances in inventory than required for compliance through the 2016 compliance period. He stated that uncertainty relating to the regulatory landscape for EAs remains and has led to very low EA prices. Mr. McCallister testified that there continues to be uncertainty about the Company's EA positions given the effects of future power, coal and gas pricing on the Company's generation fleet, along with the legal uncertainty surrounding CAIR and CSAPR. Consequently, the Company continues to assess the EA market and developments in the status of CAIR and CSAPR programs and looks for ways to optimize the EA positions by using the EA market to buy and sell EAs, as needed, passing through to customers the costs of purchases and the gains or losses on sales in the normal course of business.

Mr. McCallister testified that there were EA transactions during the reconciliation months for this proceeding, which took place prior to the Company's agreement with the OUCC not to sell additional SO_2 EAs without further discussion with their office.

Mr. McCallister explained that the Company and the OUCC have mutually agreed upon an SO_2 EA selling strategy going forward. He testified that they have agreed selling some of the Company's excess SO_2 EA allowances, given Duke Energy Indiana's net position and on-going market conditions, is a reasonable approach. Specifically, the Company would attempt to sell additional SO_2 EA allowances, but would not sell more than 50,000 SO_2 allowances in any annual period, and would stop selling SO_2 EAs once the cost basis of the EA SO_2 inventory balance reached the approximate EA value currently embedded in base rates. It was further agreed that if the approximate cost basis was reached as a result of any new SO_2 EA sales, the Company would not sell any additional SO_2 EAs without a further review of market conditions at that time and additional discussions with the OUCC. The Company will continue to monitor the developments of CAIR and CSAPR, and look for ways to optimize the Company's EA position, which could include the sale of additional CAIR seasonal NOx and annual NOx allowances.

He further stated he provided information with respect to the Company's estimated EA consumption for Ms. Douglas to use for updating estimated EA costs for the forecast months. He stated these forecasts are based on the same modeling that the Company has used for a number of years.

8. <u>Summary of OUCC's Evidence.</u> The OUCC presented the testimony of its Senior Utility Analysts, Mr. Wes R. Blakley and Ms. Cynthia M. Armstrong.

Mr. Blakley testified that he had reviewed Petitioner's filings in this Cause and the Commission's Order in ECR 21 and nothing came to his attention that would indicate Petitioner's calculation of estimated ECR adjustment factors for the relevant period is unreasonable. However, the OUCC has requested the Company recalculate its Rider 71 tracker and exclude the grossed-up federal income taxes related to AFUDC equity depreciation expense.

Mr. Blakley noted that Petitioner has fully amortized the Wheatland plant's deferred asset balance and that the revenues from the Wabash River Unit 1 can be refunded to customers. He also noted that the Company has requested recovery of costs associated with the Gallagher DSI Projects and a recalculation of depreciation expense related to the pollution control assets at retired Gallagher Units 1 and 3.

Mr. Blakely described Petitioner's proposed apportionment of the revenue from the Nucor demand charge to the impacted riders and noted that the total amount is reflected in Rider 71 to avoid a separate adjustment for all three impacted riders. Mr. Blakley also referenced that the testimony of Ms. Douglas and Mr. Howell discussed capital maintenance projects.

Mr. Blakely noted that the Company proposed a different treatment for the tax gross-up depreciation expense relating to capitalized AFUDC, which increases the tax gross-up factor, and that Petitioner's depreciation expense has been calculated pursuant to the approved depreciation rates. Mr. Blakley testified that in his experience, expenses are not typically "grossed-up" for income taxes and that such gross-ups are normally limited to utility receipts tax and IURC fees, which are based on revenue rather than income. He explained that this treatment has not been proposed in ECR proceedings previously and that the OUCC requests that the Commission deny the Company's request for this treatment. Mr. Blakley also testified that the OUCC is reserving its right to challenge a gross-up of depreciation expenses in other CWIP trackers, including the IGCC tracker.

Ms. Armstrong testified that she had reviewed Petitioner's filings and discovery in this Cause. Ms. Armstrong testified that Petitioner had seven EA sales during this period and that the OUCC agrees with the Company's EA strategy, including the set limits. The OUCC and Petitioner agreed to revisit the agreed upon EA strategy if the Company finds that it wishes to makes sales beyond the designated limits. Ms. Armstrong stated that based on her review, the Company's SO_2 sales during this period were consistent with the parties' agreement.

9. <u>Summary of Petitioner's Rebuttal Evidence</u>. Ms. Douglas responded to Mr. Blakley's testimony regarding the methodology used for converting depreciation expense to revenue requirements for Rider 71. Ms. Douglas testified that she did not agree with the OUCC's recommendations that the Commission should deny the use of the revenue conversion methodology used by the Company for depreciation expense in Rider 71 and disallow related revenue requirements. She opined that the desired consistency with the revenue conversion methodologies used in other ECR proceedings is not a valid reason for disallowing any of the proposed cost recovery.

Ms. Douglas explained that the Company has been concerned for some time that its past practice of considering only revenue-related taxes and fees in converting depreciation expense to revenue requirements in trackers did not fully cover all the taxes and fees the Company incurred related to the recovery of the cost of property via depreciation because the investment basis on which tax depreciation is determined excludes equity AFUDC. She testified that after subsequent analysis following the proceeding in Cause No. 43114 IGCC 8, the Company determined that it had incorrectly been ignoring the income taxes associated with the equity AFUDC portion of depreciation by only grossing-up depreciation for non-income tax items, and therefore, had not been recovering the income taxes associated with the recovery of depreciation in trackers. Ms. Douglas stated that this corrected methodology was used and explained in Cause Nos. 43114 IGCC 10 through IGCC 12. Once the magnitude of this issue had been identified, the Company decided to prospectively correct the methodology for ECR filings, which enables recovery for the first time in ECR proceedings of income tax costs resulting from the recovery of the costs of tracked environmental equipment via depreciation expense. Continuing, Ms. Douglas testified that making this change is consistent with the Company's past practice in making changes or corrections to a tracker and which are not taken lightly, but are made in order to get the right answer.

Ms. Douglas explained that when base rates are established, a level of income taxes is included that factors in the exclusion of equity AFUDC from the tax basis of property being depreciated, resulting in recovery of the proper level of income taxes; but for property recovered via trackers after base rates were established, that is not the case when a revenue conversion factor that excludes income taxes is used for grossing up depreciation. She explained that the methodology used by the Company in this proceeding corrects for this issue. The Company believes that this change is appropriate because it makes a correction to include income taxes in the revenue conversion factor used to gross-up the portion of depreciation expense related to the equity AFUDC included in the property investment because there will be no offsetting tax depreciation deduction for this part of the depreciation. Ms. Douglas referenced a FERC manual for interstate gas pipelines that supports the Company's decision to make this correction. She also provided an example supporting the correction.

Ms. Douglas concluded her rebuttal testimony noting that, other than Mr. Blakley's concerns regarding the Company's use of its corrected depreciation gross-up methodology, he did not question the appropriateness of the amounts included or the accuracy of the Company's rate calculations.

10. Commission Discussion and Findings. Based upon the evidence presented, the Commission finds that Petitioner's request should be approved. Specifically, the Commission finds that Petitioner should be authorized to reflect the additional values through June 30, 2013 of the NOx Compliance Plan, Phase 1 CAIR/CAMR Compliance Plan, Gallagher DSI Projects, capital maintenance, and Phase 2 MATS Compliance Projects in its rates and charges for electric service in accordance with Duke Energy Indiana's Rider 62, as indicated in the direct testimony and exhibits of Ms. Diana L. Douglas.

The OUCC took exception to Petitioner's revised methodology for converting depreciation expense into revenue requirements. More specifically, Mr. Blakley expressed concern with Petitioner's proposal to gross-up the AFUDC equity component of depreciation expense for federal income tax. He stated that, in his experience, expenses are not typically grossed-up for income taxes.

Ms. Douglas testified that making this adjustment allows the Company to fully recover its costs for income taxes related to tracked utility plant. She explained that when base rates are established, a level of income taxes is included that factors in the exclusion of equity AFUDC from the tax basis of property being depreciated. However, for property added after base rates were established with depreciation expense recovered via trackers, the additional income taxes that result are not recovered when a revenue conversion factor excluding income taxes is used for grossing-up depreciation.

Although neither Indiana statutes nor the Commission's rules specifically address the grossing-up of specific expenses for income taxes, Ind. Code § 8-1-8.8-11 provides for a utility's "timely recovery of costs and expenses incurred during construction and operation" of certain projects found to be reasonable and necessary by the Commission. In addition, Ind. Code § 8-1-2-6.6(b) provides that the Commission "...shall for ratemaking purposes add to the value of that utility's property the value of the qualified pollution control property under construction...." 170 IAC 4-6-1(o) provides that this value is "...the value of CWIP, including the amounts of AFUDC...." And, the "derivation of the utility's revenue requirement, including tax calculations, associated with the ratemaking treatment of the value of the [QPCP] under construction" shall be provided to support its requested relief. 170 IAC 4-6-19 and -12(5).

As noted by Ms. Douglas, Duke Energy Indiana has not been recovering its income tax expense associated with its tracked property and we fail to see any reason that it should not be allowed to do so now. In addition, we note that each of the other Indiana electric investor owned utilities have also utilized this method to address the AFUDC equity component in their environmental compliance rider filings. *See e.g., Indianapolis Power & Light Co.,* 42170 ECR

22, Exhibit CF-1 NOx (IURC Feb. 26, 2014) and *Northern Indiana Public Service Co.*, 42150 ECR 21, Exhibit 1, Schedule 3 (IURC Oct. 16, 2013).

Therefore, the Commission finds that Petitioner should be authorized to recover its O&M and depreciation expenses related to its NOx Compliance Plan, Phase 1 CAIR/CAMR Compliance Plan, Gallagher DSI Projects, and capital maintenance projects, in accordance with Duke Energy Indiana's Rider 71, as described in the testimony and exhibits of Ms. Douglas, including the reconciliation of such expenses for the period January 2013 through June 2013 and the estimated amounts for the period July 2013 through December 2013.

Petitioner should also be authorized to recover its SO_2 and NOx EA costs in accordance with Duke Energy Indiana's Rider 63, as described in the direct testimony and exhibits of Ms. Douglas, including the reconciliation of such expenses for the period March 2013 through August 2013 and the estimated amounts for the period March 2014 through August 2014.

The combined impact of the proposed factors for Riders 62, 63 and 71 for a typical residential customer using 1,000 kilowatt-hours is a decrease of $0.25 or 0.3% when compared to the last approved factors.

In addition, Petitioner's ongoing review progress reports related to its NOx Compliance Plan, Phase 1 CAIR/CAMR Compliance Plan, Gallagher DSI Projects, and Phase 2 MATS Compliance Projects are hereby approved. We find that the updated environmental plan, construction cost estimates and updated in-service dates for the NOx Compliance Plan and Phase 1 CAIR/CAMR Compliance Plan projects provided by Petitioner in this Cause, including changes described in the testimony of Mr. Miller, are reasonable and are hereby approved as such.

11. Confidential Information. Petitioner filed a Motion for Protection of Confidential and Proprietary Information ("Motion") with the affidavits of Mr. Miller, Mr. McCallister, and Ms. Douglas on November 26, 2013, and the amended affidavit of Mr. McCallister on December 11, 2013. In the Motion and supporting affidavits, Petitioner demonstrated a need for confidential treatment for the detailed cost estimates and actual expenditures associated with Petitioner's environmental compliance plan, unit-specific operation and maintenance costs, specific EA transaction prices, certain load and price information concerning a confidential Commission approved special contract with Nucor Steel-Indiana, certain price information for a confidential Commission approved special contract with International Paper, and certain retirement detail that contains actual costs. In Docket Entries dated December 5, 2013 and December 12, 2013, the Commission preliminarily found that such information should be subject to confidential procedures.

The Affidavits of Mr. Miller, Ms. Douglas and Mr. McCallister indicate that such confidential information has actual or potential independent economic value for Petitioner and its ratepayers, the disclosure of the confidential information could provide Petitioner's competitors and suppliers an unfair advantage, and Petitioner and its affiliates have taken all reasonable steps to protect the confidential information from disclosure. Accordingly, pursuant to Ind. Code §§ 5-14-3-4(a)(4) and 8-1-2-29, we find that the detailed cost estimates are "trade secrets" and should be afforded confidential treatment. The Commission hereby orders that procedures should be taken so that such information is appropriately secured and made available only to selected members of the Commission staff who are under an obligation not to publicly disclose such information.

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

1. Petitioner's proposed updated Rider 62, as reflected in the direct exhibits and testimony of Duke Energy Indiana, including QPCP values as of June 30, 2013, is hereby approved. The Rider 62 shall go into effect upon the filing of the final Rider with the Commission's Electricity Division for all bills rendered after the effective date of this Order.

2. Petitioner's proposed updated Rider 71, including reconciliation through June 30, 2013 and estimated amounts for July 1, 2013 through December 31, 2013, as reflected in the exhibits and testimony of Duke Energy Indiana, is hereby approved. The Rider 71 shall go into effect upon the filing of the final Rider with the Commission's Electricity Division for all bills rendered after the effective date of the Commission's Order in this proceeding.

3. Petitioner's proposed updated Rider 63, including reconciliation through August 2013 and estimated emission allowance costs for March 2014 through August 2014 as reflected in the direct exhibits and testimony of Duke Energy Indiana, is hereby approved. The Rider 63 shall go into effect upon the filing of the final Rider with the Commission's Electricity Division for all bills rendered effective with the first billing cycle of March 2014 or for bills rendered after the effective date of this Order, if later.

4. Petitioner's ongoing review progress reports related to its NOx Compliance Plan, Phase 1 CAIR/CAMR Compliance Plan, Gallagher DSI Projects, and Phase 2 MATS Compliance Projects are hereby approved.

5. Petitioner's updated environmental plan, cost estimates, and estimated in-service dates for its NOx Compliance Plan and Phase 1 CAIR/CAMR Compliance Plan projects are hereby approved as reasonable.

6. The detailed cost estimate and actual expenditure information, unit-specific operation and maintenance costs, specific EA transaction prices, International Paper price information, Nucor load and price information, and retirement detail contained in the testimony and exhibits of this case are found to be confidential and trade secrets and therefore excepted from public access.

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

ATTERHOLT, MAYS, STEPHAN, WEBER AND ZIEGNER CONCUR:

APPROVED: MAR 26 2014

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

Brenda A. Howe

Brenda A. Howe
Executive Secretary to the Commission