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; APPROVAL TO REFLECT A CHANGE DUE TO MIGRATION BETWEEN RATE CLASSES AND SEEKING APPROVAL OF AN ADJUSTMENT TO ITS RATES THROUGH ITS SO2, NOX, AND HG EMISSION ALLOWANCE ADJUSTMENT, STANDARD CONTRACT RIDER NO. 63	)	CAUSE NO. 42061 ECR 23 APPROVED: AUG 27 2014

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ORDER OF THE COMMISSION

Presiding Officers:
Angela Rapp Weber, Commissioner
Loraine L. Seyfried, Chief Administrative Law Judge

On April 28, 2014, Duke Energy Indiana, Inc. ("Petitioner," "Company" or "Duke Energy Indiana") filed a Petition with the Indiana Utility Regulatory Commission ("Commission") seeking authority to reflect additional values of Qualified Pollution Control Property ("QPCP"), as of December 31, 2013, in its rates and charges for electric service through Petitioner's QPCP Revenue Adjustment, Standard Contract Rider No. 62 ("Rider 62"). Petitioner also requests approval of: (1) an ongoing review progress report concerning certain clean coal technology projects; (2) updated environmental projects, cost estimates and estimated in-service dates for environmental projects; (3) an update and adjustment to Petitioner's Clean

Coal Operating Cost Revenue Adjustment, Standard Contract Rider No. 71 ("Rider 71"); (4) approval to reflect a change in Rider 62 and Rider 71 rate allocations; and (5) an update and adjustment to Petitioner's sulfur dioxide ("SO_2") and nitrogen oxide ("NOx"), and mercury Emission Allowance Adjustment, Standard Contract Rider No. 63 ("Rider 63").

An Evidentiary Hearing was held in this case on July 10, 2014 at 9:30 a.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. No members of the public appeared or sought to testify at the hearing

Based upon the applicable law and the evidence presented, the Commission 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 Ind. Admin. Code 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 ("CT") 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 CTs 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 24 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, this 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 No. 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 clean coal technology projects.

b. <u>CAIR and CAMR Compliance Requirements</u>. 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 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.

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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. EPA* issued an opinion 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 remains in place until EPA issues a new rule in accordance with the July 11, 2008 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 continue administering CAIR pending completion of a valid replacement rule. On April 29, 2014, the U.S. Supreme Court upheld CSAPR, reversing the D.C. Circuit's decision that vacated the rule.

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

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 megawatts ("MWs") in capacity. 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. Certain Duke Energy Indiana units have received one year MATS compliance extensions. On April 9, 2014, the Indiana Environmental Rules Board adopted the MATS provisions and repealed the CAMR at 326 IAC 24-4 that was vacated by the D.C. Circuit Court on February 8, 2008.

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 3, 2013, in Cause No. 44217, the Commission approved the Phase 2 MATS Compliance Plan projects as QPCP eligible for CWIP ratemaking treatment in accordance with Ind. Code §§ 8-1-2-6.6 and -6.8, and as clean coal and 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 ("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") (including the cost of reagents) and depreciation expenses 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 these ECR proceedings.

5. Relief Sought in this Proceeding. In this six-month update proceeding, Petitioner requests: (1) the authority to reflect additional values through December 31, 2013 of QPCP in its rates and charges for electric service, through Rider 62; (2) 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 Plan projects; (3) 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, including the reconciliation through December 31, 2013 and the estimated amounts related to its NOx Compliance Plan, Phase 1 CAIR/CAMR Compliance Plan, Gallagher DSI Projects, and capital maintenance for the period January 1, 2014 through June 30, 2014 through Rider 71 (including approval of a credit to customers of the amount of incremental demand revenues under contracts with Nucor Corporation and International Paper[3]); (4) approval to reflect a change in Rider 62 and Rider 71 rate allocations due to rate migration between High Load Factor ("HLF") and Low Load Factor ("LLF") customers consistent with the rate migration change proposed in Cause No. 43114 IGCC 12 and recently approved in Cause No. 44348; (5) approval to reflect a rate migration related to certain lighting customers, previously approved in Petitioner's last rate case, Cause No. 42359, whereas certain lighting customers were to be transitioned from one rate class to another ten years after the effective date of the order;[4] (6) 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; (7) approval of an adjustment to its rates through Rider 63, including the reconciliation through February 2014 and Petitioner's estimated SO_2 and NOx emission allowance costs for September 2014 through February 2015.

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.

[3] Formerly known as Temple-Inland.
[4] The Commission issued its Order in Cause No. 42359 on May 18, 2004.

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 coal and energy projects by creating the following financial incentives for clean coal and 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 coal and energy projects" as "projects 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 Allowance 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 case-in-chief testimony and exhibits of Mr. Joseph A. Miller, Jr., General Manager, Strategic Engineering for Duke Energy Business Services LLC; Ms. Diana L. Douglas, Director, Rates & Regulatory Planning for Duke Energy Business Services LLC; Mr. Joseph F. McCallister, Director, Gas, Oil and Emissions for 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. Joseph 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 22 ("ECR 22"), 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 Company 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 SIP Call Compliance Plan cost estimates that were previously approved have increased due to the selective catalytic reduction ("SCR") catalyst replacement project. Mr. Miller also mentioned that although the NOx projects are in-service (i.e., the equipment has been installed and is in operation), that does not mean that additional construction dollars will not be spent or recorded on the project.

Mr. Miller testified that the only projects added to the Company's current Phase 1 CAIR/CAMR Compliance Plan since the Settlement Agreement in Cause Nos. 42622/42718 have been mercury emission monitors that were under construction or purchased by the time CAMR was vacated. 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. As Mr. Miller testified in Cause No. 44418, the baghouses and DSI systems also enable Gallagher Station to comply with the MATS filterable PM and acid gas emission limits.

Mr. Miller discussed Petitioner's cost estimates for the Phase 1 CAIR/CAMR Compliance Plan projects. He explained that the estimated costs have not changed, but 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 Phase 1 CAIR/CAMR Compliance Plan estimated costs are the same as the estimated costs approved in ECR 22. 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 Phase 1 CAIR/CAMR Compliance Plan continue to be reasonable.

Mr. Miller discussed the status of Petitioner's Gallagher Units 2 and 4 compliance 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 progress report on the Gallagher DSI Projects stating that construction and testing of the 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 Gallagher DSI Projects remain the same as in the Company's last progress report, and that the Company does not currently foresee a risk for the need for ash fixation based on the use of hydrated lime as the reagent in the DSI system. Mr. Miller also explained that with the development of the lined landfill cell at Gallagher, the Company is planning to cap the currently open landfill cell containing the initial trona-based waste product that was the original basis of the potential need for ash fixation and does not foresee a need to have to fixate any ash that has already been placed.

Referencing Cause No. 44217, Mr. Miller next discussed the reasons Petitioner is constructing the Phase 2 MATS Compliance Plan projects. 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. He stated the primary focus of the plan is reducing the mercury emissions at Cayuga and Gibson stations. But, the Company has filed a Phase 3 Compliance Plan[5] seeking approval of remaining investments needed to ensure and demonstrate compliance with MATS limits, mainly at Gibson Station.

[5] Cause No. 44418.

Mr. Miller described the Company's approved current Phase 2 MATS Compliance Plan. He explained that in the Company's Phase 3 Compliance Plan filing, the Company proposed to withdraw its previous request made in its Phase 2 plan to install an activated carbon injection ("ACI") system 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.

Mr. Miller testified that the estimated costs of the Phase 2 MATS Compliance Plan have not changed, but indicated the Company is awaiting a Commission Order in Phase 3 before reflecting the proposed Gibson Unit 5 change (from ACI to calcium bromide) to the Phase 2 cost estimate. He stated the Company believes that the Phase 2 MATS Compliance Plan projects will be completed on time and within the approved cost estimate. However as with any multi-year plan, he would expect to see minor changes from ongoing impacts and refinements to the projects as a normal part of ongoing construction program. Mr. Miller explained that the Company is currently working on the future Cayuga SCR catalyst replacement program forecast, which will be similar to what has been presented in these proceedings for Gibson.

Mr. Miller explained the status of construction at Cayuga as of the end of December 2013: the general works contractor continued SCR ductwork and structural steel erection, the project has completed its SCR caisson and foundation work, set the ammonia tanks, and completed the tier 1 steel erection on both units. The ammonia storage area and trench work is also in progress. And, the civil general works contract for the Cayuga sorbent projects was awarded in July 2013.

b. **<u>Rider 62</u>.** Ms. Diana 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 investment through December 31, 2013 for approved NOx Compliance Plan and Phase 1 CAIR/CAMR Compliance Plan projects (and of 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 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 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 that her Exhibit B-2 reflects an adjustment to account for the decision not to go forward with the mercury continuous emission monitoring system ("CEMS") project for stack B at Gallagher Station and to instead install a mercury sorbent trap under the remaining budget for the original mercury monitor project. Therefore, the costs for the CEMS project have been removed from the investment balance, so that the Company will no longer earn a return.

Ms. Douglas explained the costs of capital maintenance projects associated with the approved NOx 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 and 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. Charles Howell discussed the 35 capital maintenance projects for which costs, incurred after June 30, 2011, have been included. Mr. Howell explained that 24 of the projects have been approved for recovery in prior ECR proceedings and 26 of the projects are in service as of the December 31, 2013 cutoff for this filing. The 11 new capital maintenance projects included for Commission approval in this rider proceeding are as follows:

Project	Equipment Type	Completion Status
Cayuga 1 Density Meter on Limestone Feed	FGD[6]	In Service
Cayuga 2 Density Meter on Limestone Feed	FGD	In Service
Gallagher 4 Baghouse Bag Replacement	Baghouse	In Service
Gibson 1 Mercury Sample Probe and Umbilical	CEMS	In Progress
Gibson 2 Mercury Sample Probe and Umbilical	CEMS	In Progress
Gibson 4 Mercury Sample Probe and Umbilical	CEMS	In Progress
Gibson 4 SCR SBS Probes	SCR	In Progress
Gibson 5 Mercury CEMS Nitrogen Generator	CEMS	In Progress
Gibson 1-3 FGD Personnel Elevator	FGD	In Progress
Gibson 1-5 Ammonia Tank Fogging System	SCR	In Progress
Gibson 1-5 SCR SA Compressed Air Piping	SCR	In Progress

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

[6] Flue Gas Desulfurization.

Station. In addition, with the installation of SCRs at Cayuga, there will also be periodic replacement of catalyst layers just as at Gibson.

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

Ms. Douglas explained the amount of accumulated depreciation as of December 31, 2013 that is applicable to the investment for projects under the NOx and Phase 1 CAIR/CAMR Compliance Plans and their related capital maintenance projects, as well as for the Gallagher DSI Projects. She also explained how the retirement of Gallagher Units 1 and 3 in January 2012 was 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. She said this is 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 provided an update regarding the amount of 2012-pay-2013 property tax expense in relation to the property tax refund terms approved in Cause No. 42359. She stated that the final amount of retail jurisdictional 2012-pay-2013 property tax expense exceeds the level built into base rates, so no further refund is due customers. She also indicated that no further calculation or reporting is needed in future ECR proceedings.

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 December 31, 2013, and the estimated costs for the period January through June 2014. Ms. Douglas also testified that the Company is requesting the continued recovery of amortization of the Phase 2 MATS Compliance Plan development costs over a three-year period, as presented and approved in Cause No. 42061 ECR 21. The Company is also requesting approval of the inclusion of the amortization of post-in-service carrying costs accrued on the Gallagher DSI Projects, approved in Cause No. 43956, over the remainder of the amortization period of the Phase 2 MATS Compliance Plan development costs.

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 systems, 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 I CAIR/CAMR Compliance Plan. He explained that the projects associated with these expenses are the Cayuga Station Units 1 and 2 FGDs, Gibson Station Units 1-3 FGDs, Gibson Station Units 4 and 5 FGD upgrades, and Gallagher Station Units 1-4 baghouses and that he anticipates having O&M expenses associated with mercury monitoring at all stations in the future. 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, and as such the estimated depreciation expense for the Gallagher Units 1 and 3 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 which had been previously used for the NOx Compliance Plan and 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 most recently Commission-approved depreciation rates (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 2012 Settlement Agreement provision that allowed the Company to continue to use the accelerated rates previously approved by the Commission for depreciation of NOx Compliance Plan and Phase 1 CAIR/CAMR Compliance 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 the amortization of Phase 2 MATS Compliance Plan development costs and post-in-service carrying costs accrued on the Gallagher DSI Projects to revenue requirements. She testified that depreciation expense and the amortization of post-in-service carrying costs accrued on the Gallagher DSI Projects were 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 or amortized.[7] The portion of depreciation or amortization 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 and amortization expense was converted to revenue requirements using the same revenue conversion factor as for O&M and Phase 2 MATS Compliance Plan development costs.

Ms. Douglas also testified that the Company was including credits to customers in the amount of incremental demand revenues under contracts with Nucor Corporation ("Nucor

[7] This includes direct costs and debt AFUDC.

Credit") and International Paper ("International Paper Credit"). 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 July through December 2013 was included in the development of the revenue requirement used in developing the Rider 71 factors. The Nucor Credit was calculated in accordance with the Commission's February 24, 2010 Order in Cause No. 43754 and its August 18, 2010 Order in Cause No. 42061 ECR 15 ("ECR 15 Order") using the revenue requirements proposed in this ECR 23 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, which was approved by the Commission on September 11, 2013). Ms. Douglas testified that the International Paper Credit was calculated in accordance with the Commission's January 25, 2012 Order in Cause No. 44087 and its ECR 15 Order (related to the Nucor Credit) using actual steam demand for the period July through December 2013 and the revenue requirements proposed in this proceeding for Riders 62 and 71 (excluding the Nucor Credit and International Paper Credit).[8] 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.

Finally, Ms. Douglas testified with regard to the proposed changes to the allocations used in Riders 62 and 71. She explained that after a review of changes in the number of and sales to Rate HLF and LLF industrial customers since the last rate case, the Company proposed a rate migration adjustment, consistent with the rate migration adjustment proposed in pending Cause No. 43114 IGCC 12 and more recently approved in Cause No. 44348. Ms. Douglas explained that this migration results in a reduction in the Rate HLF share and an increase in the Rate LLF share of the kilowatt system peak of approximately 50 MW and results in a change in the allocation percentages of approximately 1%. She further explained that the Company would continue to monitor the rate migrations between Rate HLF and Rate LLF each year and if there is a net change of greater than 10 MW from the current level, the Company would propose an update to the allocation percentages at that time. Ms. Douglas also discussed that in accordance with the Commission's May 18, 2004 Order in Cause No. 42359, certain lighting customers were to be transitioned from two rate classes[9] into another lighting rate class,[10] at the end of ten years. She explained that these adjustments will be made on a going forward basis in this and other riders using historical demand allocations.

d. <u>Rider 63</u>. Ms. Douglas explained and supported Petitioner's proposed adjustments to Rider 63, covering the reconciliation of SO_2 and NOx net EA expenses versus the net expenses incurred for the six months ended February 2014, and the estimated NOx and SO_2 EA costs for the period September 2014 through February 2015.

Ms. Douglas testified that a proposed factor of $0.000156 per kWH is being requested for the September 2014 through February 2015 billing period. Ms. Douglas testified that this factor

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[8] Rider 61 is not applicable to the International Paper steam contract.
[9] Area lighting and outdoor lighting.
[10] Unmetered outdoor lighting service and metered outdoor lighting service.

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. Joseph McCallister explained the history and current status of CAIR and CSAPR. Most recently, on April 29, 2014, the U.S. Supreme Court upheld CSAPR, reversing the D.C. Circuit Court's decision that vacated the rule. He stated that EPA's next steps are not known and as such, the Company will continue to monitor developments. However, at this time, it is anticipated that CAIR will be in effect for 2014 EA Compliance.

Mr. McCallister also explained the current status of CSAPR's impact on the CAIR programs, CAIR allowances in inventory, and compliance. He stated that the compliance filings for 2013 were completed under CAIR compliance requirements. In addition, EPA has allocated 2014 annual and seasonal CAIR NOx allowances. Mr. McCallister further explained that while CAIR is in effect, SO_2 compliance will take place under the CAIR rules using the compliance ratio mandated by CAIR and that the ratio is increasing. He summarized that given the current status of CSAPR and assuming CAIR is in place for the 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 vacatur of CSAPR in August 2012 and receipt of the 2014 vintage CAIR allowances to the accounts, market activity for CAIR allowances continues to be limited. He said that based on recent market activity, as of April 2014, the approximate market prices for 2014 CAIR SO_2 EAs are approximately $0.75/EA, 2014 CAIR annual NOx EAs are approximately $47/EA, and 2014 CAIR seasonal NOx EAs are approximately $24/EA.

Mr. McCallister further testified that since the vacatur of CSAPR and the recent U.S. Supreme Court ruling associated with CSAPR, there has been no compliance needs for 2012 or 2013. He went on to state that, to date, the Company has not observed any CSAPR EA market activity during 2013 or 2014. In addition, there are currently no market quotes available for CSAPR EAs.

Mr. McCallister described the types of transactions that occur in the EA market and why it is necessary for Duke Energy Indiana to participate. He described the 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. He stated that the model is just a tool, and that judgment must be applied to the output. Mr. McCallister explained that the model distinguishes between native load EA requirements and EAs to support non-native sales, and those 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. All zero cost allowances 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 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, 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 noted 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. Mr. McCallister further explained that the Company continues to assess the EA market and developments in the on-going status of CAIR and CSAPR programs to look for ways to optimize the EA positions.

Mr. McCallister testified that there were EA transactions during the reconciliation months for this proceeding and summarized these transactions in Confidential Exhibit C-1. He explained the SO_2 EA sales were within the parameters that Duke Energy Indiana and the OUCC agreed to during the Fall of 2013. He testified that 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 of approximately \$14.6 million. The total number of SO_2 EAs sold was 12,700 and all these sales were made during the month of February 2014. He further testified that the cost basis of the SO_2 EA inventory at the end of February 2014 was approximately \$17.5 million and once the SO_2 inventory cost basis reaches the \$14.6 million level, Duke Energy Indiana will not sell any additional SO_2 EAs without further 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 and annual NOx allowances.

Finally, he stated that 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 that these forecasts are based on the same modeling that the Company has used for a number of years.

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

Mr. Blakley testified he reviewed Petitioner's filings in this Cause and the Commission's Order in ECR 22 and nothing came to his attention that would indicate Petitioner's calculation of estimated ECR adjustment factors for the relevant period is unreasonable. 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. Blakley 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. Mr. Blakley also noted that the testimony of Ms. Douglas and Mr. Howell discussed capital maintenance projects.

Mr. Blakley also noted that Petitioner had significant rate migration from Rate HLF to Rate LLF and that the Company proposed to adjust the allocation for the net migrations between the two classes by reducing the Rate HLF and increasing the Rate LLF share of the kilowatt system peak. He stated this change would not affect the allocation to other customer classes. Mr. Blakley also noted that Petitioner referenced a transition between lighting rate classes as required by Cause No. 43259, which transition started in May 2014. He stated this required lighting rate class migration also does not affect the total allocation to other customer classes.

Ms. Cynthia Armstrong testified that she reviewed Petitioner's filings in this Cause. She testified that Petitioner had four EA sales during this period and that the strategy utilized in selling the excess SO_2 EAs was consistent with the Company and the OUCC's agreement outlined in ECR 22. Ms. Armstrong further testified that based on her analysis, Duke Energy Indiana's calculations of the EA adjustment factor were accurately applied.

9. <u>Commission Discussion and Findings</u>. Based on 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 December 31, 2013 of the NOx Compliance Plan, Phase 1 CAIR/CAMR Compliance Plan, Gallagher DSI Projects, capital maintenance, and Phase 2 MATS Compliance Plan 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 Commission also 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, capital maintenance, and Phase 2 MATS Compliance Plan, 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 July 2013 through December 2013 and the estimated amounts for the period January 2014 through June 2014.

The OUCC noted the Company's proposed rate migration from Rate HLF to Rate LLF and the allocation adjustment between the two classes. Mr. Blakley testified that this change would not affect the allocation to other customer classes. Mr. Blakley also noted the transition between lighting rate classes as required by Cause No. 43259, which transition started in May 2014. He noted that this required lighting rate class migration also does not affect the total allocation to other customer classes. Accordingly, Commission hereby approves the change in Rider 62 and Rider 71 rate allocations due to the rate migration between HLF and LLF customers and certain lighting rate classes.

Based on the evidence presented, 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 September 2013 through February 2014 and the estimated amounts for the period September 2014 through February 2015.

The combined impact of the proposed factors for Riders 62, 63 and 71 for a typical residential customer using 1,000 kilowatt-hours would be an increase of $0.36 or 0.4% 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 Plan 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, including changes described in the testimony of Mr. Miller, are reasonable and approved as such.

10. **Confidential Information.** Petitioner filed a Motion for Protection of Confidential and Proprietary Information ("Motion") with the Affidavits of Mr. Joseph A. Miller, Jr., Mr. Joseph F. McCallister, and Ms. Diana L. Douglas on May 13, 2014. In this Motion, 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, certain price information for a confidential Commission approved special contract with International Paper, and certain retirement detail that contains actual costs. In a May 15, 2014 Docket Entry, the Presiding Officers 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 information contains "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 investment values as of December 31, 2013, is hereby approved, including the adjustments made to the allocations for certain industrial customers and between certain lighting rate classes. The Rider 62 rates 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 December 31, 2013 and estimated amounts for January 1, 2014 through June 30, 2014, as reflected in the exhibits and testimony of Duke Energy Indiana, is hereby approved, including the amortizations of Phase 2 MATS Compliance Plan development costs and post-in-service

carrying costs accrued on the Gallagher DSI Projects, as well as adjustments made to the allocations for certain industrial customers and between certain lighting rate classes. The Rider 71 rates 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 February 2014 and estimated emission allowance costs for September 2014 through February 2015 as reflected in the direct exhibits and testimony of Duke Energy Indiana, is hereby approved. The Rider 63 rates 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 September 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 Plan 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.

STEPHAN, MAYS-MEDLEY, WEBER, AND ZIEGNER CONCUR:

APPROVED: AUG 27 2014

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

Brenda A. Howe

Brenda A. Howe
Secretary to the Commission