

ORIGINAL

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

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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 HLF AND LLF)
INDUSTRIAL RATE CLASSES; 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 24

APPROVED:

FEB 11 2015

ORDER OF THE COMMISSION

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

On October 28, 2014, Duke Energy Indiana, Inc. (“Petitioner” or “Duke Energy Indiana”) filed a Petition for environmental cost recovery (“ECR”) with the Indiana Utility Regulatory Commission (“Commission”) seeking authority to reflect additional values of qualified pollution control property (“QPCP”), as of June 30, 2014, in its rates and charges for electric service through Petitioner’s Qualified Pollution Control Property Revenue Adjustment, Standard Contract Rider No. 62 (“Rider 62”). Petitioner further 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) a rate migration between High Load Factor ("HLF") and Low Load Factor ("LLF") customers; and (5) an update and adjustment to Petitioner's Emission Allowance Adjustment, Standard Contract Rider No. 63 ("Rider 63").

An evidentiary hearing was held on January 7, 2015, 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 and participated at the hearing. 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 now finds:

1. Notice and Jurisdiction. Due, legal, and timely notice of the evidentiary hearing was given and published by the Commission. 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, -6.8, and -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. Duke Energy Indiana 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, Duke Energy Indiana'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 nitrogen oxide ("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 clean coal technology 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 required major sulfur dioxide (“SO₂”) and NOx emission reductions, established annual and seasonal NOx trading programs, and set limitations on the use of SO₂ emission allowances. The Indiana Air Pollution Control Board adopted CAIR on November 1, 2006.¹

The final CAMR provides regulatory authority for a mercury cap and trade program. The Indiana Air Pollution Control Board adopted CAMR on October 3, 2017.²

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 Phase 1 CAIR/CAMR Compliance Plan.

c. Mercury and Air Toxic Compliance Requirements. The EPA first proposed Maximum Achievable Control Technology 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.

¹ CAIR has since been replaced by the Cross State Air Pollution Rule, which was upheld by the U.S. Supreme Court on April 29, 2014, in *State of North Carolina v. EPA*.

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

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. 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.

On August 27, 2014, in Cause No. 44418, the Commission approved the Phase 3 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, 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, 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 Adjustment. In Cause Nos. 42411 and 42359, the Commission approved the recovery of emission allowance ("EA") costs for NO_x emissions in Petitioner's then-existing SO₂ 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 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 proceedings.

5. Relief Sought in this Proceeding. In this six-month update proceeding, Petitioner specifically seeks: (1) to reflect additional values through June 30, 2014, 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 and Phase 3 MATS Compliance Plans; (3) approval for 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 June 30, 2014, 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 July 1, 2014, through December 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 Paper³); (4) approval of the amounts included for recovery in Rider 71 for the amortization of the Phase 2 and Phase 3 MATS Compliance Plans development costs and the post-in-service carrying costs accrued at Duke Energy Indiana's allowance for funds used during construction ("AFUDC") rate for the Gallagher DSI Projects; (5) approval to reflect a change in Rider 62 and Rider 71 rate allocations due to rate migration between HLF and LLF customers consistent with the rate migration change approved in Cause No. 42061 ECR 23 ("ECR 23"); (6) approval of Petitioner's updated environmental plan, cost estimates, and estimated in-service dates for the NOx Compliance Plan; Phase 1 CAIR/CAMR Compliance Plan; and Phase 2 and Phase 3 MATS Compliance Plans; (7) approval of an adjustment to its rates through Rider 63, including the reconciliation through August 2014 and Petitioner's estimated SO₂ and NOx EA costs for March 2015 through August 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. 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. 170 IAC 4-6-9 and -18.

³ Formerly known as Temple-Inland.

c. **Clean Energy Project 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 certain financial incentives for projects found to be reasonable and necessary, including the timely recovery of costs incurred during construction and operation and any 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., Vice President of Central Engineering and Services, Ms. Diana L. Douglas, Director, Rates & Regulatory Planning, Mr. Joseph F. McCallister, Director, Gas Oil and Emissions, and Ms. Jennifer M. Pope, Midwest Director Fossil-Hydro Finance.

a. **Compliance Plan Project Reports.** Mr. Miller stated Petitioner is constructing its NOx Compliance Plan projects to comply with federal and state NOx SIP Call regulations that took effect in May 2004. 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 ECR 23.

Mr. Miller reiterated that the estimated costs of the NOx Compliance Plan have changed, but that Petitioner’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 added that with the Commission’s approval, for CWIP ratemaking purposes, Petitioner proposes to include the actual costs of the projects once they are known, whether higher or lower than the original estimates. Mr. Miller testified that the NOx Compliance Plan cost estimates previously approved reflect adjustments due to future Gibson catalyst bed replacement projects, but the addition of another year to the forecast results in a slight overall increase in the total plan cost. Mr. Miller also noted that although the NOx projects are in-service,⁴ additional construction dollars may be spent or recorded on the project.

Mr. Miller testified the only projects added to the current Phase 1 CAIR/CAMR Compliance Plan since the Settlement Agreement in Cause Nos. 42622 and 42718 have been mercury emission monitors that were under construction or purchased by the time CAMR was vacated.

Mr. Miller described the emission benefits associated with the Gallagher baghouses. He explained that the baghouses resulted in significant decreases in emission rates of filterable

⁴ “In-service” means the equipment has been installed and is in operation.

particulate matter, mercury, and SO₂. The baghouses and DSI systems also enable the Gallagher Station to comply with the MATS filterable particulate matter and acid gas emission limits.

Mr. Miller discussed Petitioner's cost estimates for the Phase 1 CAIR/CAMR Compliance Plan projects. He explained the estimated costs have not changed, but 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, the Phase 1 CAIR/CAMR Compliance Plan estimated costs are the same as the estimated costs approved in ECR 23. However, Petitioner proposes, 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. Mr. Miller stated he believes the current cost estimates of the Phase 1 CAIR/CAMR Compliance Plan continue to be reasonable.

Mr. Miller provided Petitioner's progress report on the Gallagher DSI Projects. The construction and testing of the DSI systems on Units 2 and 4 were substantially complete in 2010, and 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 Petitioner's last progress report.

Next, Mr. Miller discussed the reasons Petitioner is constructing the Phase 2 MATS Compliance Plan projects, which were approved in Cause No. 44217. He explained Petitioner must further reduce the mercury emissions from its generating facilities to comply with the MATS rule and its anticipated compliance date of April 16, 2015. He noted the primary focus of the plan is reducing the mercury emissions at the Cayuga and Gibson Stations.

Mr. Miller stated Duke Energy Indiana received approval in Cause No. 44418 of its Phase 3 MATS Compliance Plan needed to ensure and demonstrate compliance with MATS limits, mainly at Gibson Station. He explained that in Cause No. 44418, Petitioner proposed to withdraw its previous request 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 Petitioner intends to defer installation of the ACI projects previously approved for Cayuga pending additional mercury emission testing after the selective catalytic reduction systems ("SCR") 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 changed due to the Commission's approval of the Phase 3 MATS Compliance Plan, which changes the Gibson Unit 5 ACI to calcium bromide. The cost estimate also reflects the deferral of the Cayuga ACI systems. Mr. Miller again explained he expects to see minor changes from ongoing impacts and refinements to the projects as a normal part of an ongoing construction program. He further explained that Petitioner 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 described the status of construction at Cayuga as of the end of June 30, 2014, noting: the general works contractor continued SCR ductwork and structural steel erection; tiers 1, 2, and 3 steel erection on both units has been completed; the reactor cap on Unit 1 and the Unit 1 ID fan have been set; and the Unit 2 ID fan and SCR reactor work continues with installation completion planned for outages. The civil general works contract for the Cayuga sorbent projects was completed in March 2014 and the mechanical general works contract was awarded in March 2014, with the mechanical work commencing in April 2014.

Mr. Miller explained that there are not any changes to the Phase 3 MATS Compliance Plan and that the estimate has not changed since Commission approval. However, as with Petitioner's other plans, he expects to see minor changes from ongoing impacts and refinements to the projects as a normal part of an ongoing construction program.

Mr. Miller described the status of the Phase 3 MATS Compliance Plan construction as of June 30, 2014, noting: the particulate matter continuous emission monitoring systems ("CEMS") at Gibson and Cayuga are installed and operating; the Gibson Unit 4 precipitator refurbishment outage is under way and demolition is essentially complete; the new precipitator internals and ductwork have been installed; the penthouse has been installed; and the new electrical feeds are being made.

Mr. Miller concluded with an update on Cross State Air Pollution Rule ("CSAPR") explaining that the stay of CSAPR has been lifted by the D.C. Circuit Court and the rule will go into effect as of January 1, 2015. He testified the suite of environmental controls that have been or are being installed, along with planned unit retirements, positions Duke Energy Indiana well to comply with CSAPR and does not require any changes or additions to any of its compliance plans at this time.

b. Rider 62. 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 investment through June 30, 2014, for approved NOx and Phase 1 CAIR/CAMR Compliance Plan projects (and of related capital maintenance projects), the Gallagher DSI Projects, and the Phase 2 and Phase 3 MATS Compliance Plan 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 until the Commission determines that these projects are used and useful in a base rate proceeding or until these projects no longer satisfy the other requirements of the Commission's CWIP rules. Until such time, Petitioner will continue to receive revenues through Rider 62.

Ms. Douglas testified regarding how retirements have been accounted for on Duke Energy Indiana's accounting books and records pursuant to U.S. Generally Accepted Accounting Principles. She stated the retirements reflected in this filing are all considered normal retirements. In addition, she explained that because depreciation of an asset on the accounting

books stops upon retirement, Petitioner has reflected this in the actual and estimated depreciation amounts as appropriate based on the dates the equipment was retired.

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

Ms. Pope discussed the 42 capital maintenance projects for which costs incurred after June 30, 2011, have been included. Ms. Pope explained that 35 of the projects have been approved for recovery in prior ECR proceedings and 32 of the projects are in service as of June 30, 2014, the cutoff for this filing. The seven new capital maintenance projects included for Commission approval in this proceeding are:

Project	Equipment Type	Completion Status
Cayuga Unit 1 MCEMS Replacement	CEMS	In Progress
Cayuga Unit 2 MCEMS Replacement	CEMS	In Progress
Cayuga Unit 2 Absorber Door Replacement	FGD ⁵	In Service
Cayuga GH-3A Conveyor Belt	FGD	Complete
Cayuga FGD WWT Density Forward Feed Pumps	FGD	In Service
Gibson FGD 1-3 GH1A Conveyor Belt	FGD	Complete
Gibson FGD 3 #3 Vacuum Pump Gearbox	FGD	Complete

Additionally, Ms. Pope testified about other future maintenance projects, such as continued replacement of the absorber piping, gearboxes, and ball mill liners on FGD equipment at Gibson Station. She noted with the installation of SCRs at Cayuga, there will also be periodic replacement of catalyst layers as at Gibson.

Ms. Douglas explained the inclusion of costs associated with the Gallagher DSI Projects and the Phase 2 and Phase 3 MATS Compliance Plan projects. She also explained the amount of accumulated depreciation, as of June 30, 2014, that is applicable to the investment for projects under the NOx and Phase 1 CAIR/CAMR Compliance Plan projects and their related capital maintenance projects as well as for the Gallagher DSI Projects. Ms. Douglas also explained how the retirement of Gallagher Units 1 and 3 in January 2012 was reflected.

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 the Wheatland Plant. In accordance with the Commission’s Order in

⁵ Flue Gas Desulfurization

consolidated Cause Nos. 42908 and 43211 approving the sale of Wabash River Unit 1 to Wabash Valley Power Association, the credit is included in the Rider 62 revenue requirement calculation.

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, 2014, and the estimated costs for the period July through December 2014. She stated Petitioner requests 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, and post-in-service carrying costs accrued on the Gallagher DSI Projects, as approved for recovery in Rider 71 in ECR 23. Petitioner also requests, for the first time, approval of the amortization of the Phase 3 MATS Compliance Plan development costs over a three-year period, as approved in Cause No. 44418. In addition, Petitioner requests approval of the inclusion of a credit to customers under a contract with Nucor and International Paper, which has been apportioned to Rider 61 as well as to Riders 62 and 71.

Ms. Pope testified the projects having incremental O&M expenses associated with the 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 sulfur trioxide mitigation systems. With regard to the incremental O&M expenses associated with the Phase 1 CAIR/CAMR Compliance Plan, she 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 baghouses. She stated Petitioner also expects to have O&M expenses associated with mercury monitoring at all stations in the future. Ms. Pope identified the incremental O&M expenses associated with the Gallagher DSI Projects. She explained that the incremental costs associated with all of these projects will vary based on demand and the generation level of the units. Finally, Ms. Pope discussed the O&M expenses that will be expected with the Phase 2 and Phase 3 MATS Compliance Plan projects.

Ms. Douglas explained that pursuant to the Consent Decree entered into by Petitioner and the U.S. Department of Justice resolving New Source Review litigation, Duke Energy Indiana 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 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 and Phase 1 CAIR/CAMR Compliance Plan projects.

Ms. Douglas further explained that both Petitioner's capital maintenance projects and Gallagher DSI Projects are being depreciated using the depreciation rates approved in Cause No. 43114 IGCC 4S1 based on the FERC accounts associated with the property. She stated that the Order in that Cause also approved a provision of a 2012 Settlement Agreement allowing Duke Energy Indiana to continue to use the accelerated rates previously approved by the Commission for depreciation of the NOx 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 the Phase 2 and Phase 3 MATS Compliance Plan development costs and post-in-service carrying costs to revenue requirements. She testified that depreciation expense and the amortization of post-in-service carrying costs were separated into two components before converting to revenue requirements: (1) the portion related to equity AFUDC, and (2) the portion related to all other costs comprising the investment being depreciated or amortized. The portion of depreciation and post-in-service carrying cost 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. The remainder of the depreciation and post-in-service amortization expense was converted to revenue requirements using the same revenue conversion factor as for O&M and the Phase 2 and Phase 3 MATS Compliance Plan development costs.

Ms. Douglas also testified that Petitioner included credits to customers in the amount of incremental demand revenues under contracts with Nucor Corporation (“Nucor 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 2015 demand revenues applicable to Nucor’s interruptible load and a reconciliation of the credit applicable to January through June 2014 was included in the revenue requirement used in developing the Rider 71 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 and International Paper Credits) and the revenue requirements from the most recently approved Rider 61 in 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 using actual steam demand for the period January through June 2014 and the revenue requirements proposed in this proceeding for Riders 62 and 71 (excluding the Nucor and International Paper Credits).⁶ 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.

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, Petitioner proposed a rate migration adjustment, which was approved in ECR 23.⁷ Ms. Douglas explained that this migration through 2012 resulted in an adjustment of approximately 50 MW moving from Rate HLF to Rate LLF. She further explained that Petitioner committed to monitoring the rate migrations between these classes each

⁶ Rider 61 is not applicable to the International Paper steam contract.

⁷ Petitioner also received approval in ECR 23 of an adjustment to allocation factors used in Riders 62 and 71 related to the May 2014 transition of certain lighting customers from two rate classes (AL and OL) to another lighting rate class (UOLS). The transition was made pursuant to the Commission’s Order in Cause No. 42359.

year. If there is a net change of greater than 10 MW from the 2012 level, Petitioner will propose an update to the allocation percentages at that time. Ms. Douglas explained that Petitioner completed the 2013 study, which resulted in an additional migration of approximately 26 MW from Rate HLF to Rate LLF, and that this additional migration has been included in the development of Rider 62 and 71 rates in this proceeding.

d. Rider 63. Ms. Douglas explained and supported Petitioner's proposed adjustments to Rider 63, covering the reconciliation of SO₂ and NO_x net EA expenses versus the net expenses incurred for the six months ended August 2014, and the estimated mercury, NO_x and SO₂ EA costs for the period March through August 2015.

Ms. Douglas testified that a proposed factor of \$0.000077 per kWh is requested for the March through August 2015 billing period. She said the development of this factor included an accounting correction in the amount of \$964 that was made in March 2014, to the realized gain amount that resulted from the sale of Annual NO_x EAs recorded during February 2014, and which was included in ECR 23. She further testified that no estimates were included of EA sales during the projected period.

Ms. Douglas testified that Petitioner did not reflect any impacts from the recent D.C. Circuit Court ruling regarding the implementation of CSAPR in the March through August 2015 forecast used in this filing because it is too early to reasonably and accurately forecast any impacts. The reconciliation in the next ECR filing of the actual costs incurred for the March through August 2015 period to this forecast will reflect any changes due to CSAPR.

Mr. McCallister provided an update on the status of CSAPR since Petitioner's last ECR proceeding, stating that on October 23, 2014, the D.C. Circuit Court granted EPA's motion to lift the stay on CSAPR effective January 1, 2015. He said with this recent announcement, Petitioner is in the process of updating its forecasts under the assumption that CSAPR will be in place for 2015.⁸

Mr. McCallister explained how the reinstatement of CSAPR affects the CAIR programs, CAIR allowances in inventory, and compliance. He testified that CAIR will remain in place for the 2014 compliance period with CSAPR being effective January 1, 2015. For 2014, Duke Energy Indiana will have to continue to comply with the requirements of CAIR Annual NO_x, CAIR Seasonal NO_x, and Title IV/Acid Rain SO₂ using the CAIR SO₂ ratio requirements. For 2015, Duke Energy Indiana will have to comply with the requirements of CSAPR Annual NO_x, CSAPR Seasonal NO_x, CSAPR SO₂ and Title IV/Acid Rain SO₂ using the pre-CAIR allowance ratio requirement of one allowance to one ton of emissions.

Mr. McCallister described the trading market for CAIR and CSAPR EAs. He stated that since the lifting of the stay on CSAPR was so recent, there has not been time to observe new market activity or market prices for CSAPR allowances. He said market activity for CAIR allowances continues to be limited and based on recent market activity. As of late October 2014, the approximate market prices for 2014 CAIR SO₂ EAs are approximately \$0.75/EA, 2014

⁸ Mr. McCallister also noted that Petitioner's forecast in this proceeding was prepared without this information and does not reflect the lifting of the stay on CSAPR.

CAIR Annual NO_x EAs are approximately \$51/EA, and 2014 CAIR Seasonal NO_x EAs are approximately \$28/EA. Petitioner expects CSAPR market activity to develop over the next few months and will provide an update in its next ECR proceeding.

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 production costing model that Petitioner uses to determine whether it needs to purchase EAs or if it has a surplus and can sell some of its EA inventory. He said 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 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 Petitioner 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 its position in later years.

Next, Mr. McCallister described how the recent CSAPR announcement would affect the management of the CAIR and CSAPR EA positions for 2014 and 2015. He explained Petitioner's current positions concerning CAIR SO₂ and Seasonal and Annual NO_x EAs. Petitioner projects it will have more allowances in inventory than required for compliance under CAIR through the 2014 compliance period. Beginning with CSAPR compliance in 2015, CAIR will no longer be in place and the CAIR allowances can no longer be used for compliance purposes. He said Petitioner is continuing to review the available information and is updating its projected SO₂ and NO_x usage for 2015. Petitioner will also continue to monitor developments in this area and look for ways to optimize the EA positions.

Mr. McCallister testified that there were not any EA transactions during the reconciliation months for this proceeding. He further stated he provided information with respect to Petitioner's estimated EA consumption to Ms. Douglas for use in updating estimated EA costs for the forecast months. He stated these forecasts are reasonable and based on the same modeling that has been used for a number of years.

8. Summary of the OUCC's Evidence. 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 23 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 Petitioner has requested recovery of costs associated with the Gallagher DSI Projects, approved December 28, 2011 in Cause No. 43956, and 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 said that the testimony of Ms. Douglas and Ms. Pope discussed capital maintenance projects. Mr. Blakley noted that Petitioner continues to have rate migration from Rate HLF to Rate LLF. He said Petitioner 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 KW system peak and noted this change would not affect the allocation to other customer classes.

Ms. Armstrong testified that she reviewed Petitioner's filings in this Cause. She testified that Petitioner did not have any EA sales during this period. She further testified that based on her analysis, Duke Energy Indiana's calculations of the EA adjustment factor were accurately applied.

9. Commission Discussion and Findings. Based upon the evidence presented as discussed above, we find Petitioner's requested relief is reasonable, consistent with regulatory requirements and prior Commission Orders, and should be approved. Specifically, costs and expenses through June 30, 2014, for the NOx Compliance Plan, Phase 1 CAIR/CAMR Compliance Plan, Gallagher DSI Projects, capital maintenance, and the Phase 2 and Phase 3 MATS Compliance Plans shall be included in Petitioner's 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. Douglas.

Petitioner is 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, 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 2014 through June 2014, and the estimated amounts for the period July 2014 through December 2014.

The OUCC noted Petitioner'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. Accordingly, we approve the change in Rider 62 and Rider 71 rate allocations due to the rate migration between HLF and LLF customers.

Petitioner is also authorized to recover its SO₂ 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 2014 through August 2014 and the estimated amounts for the period March 2015 through August 2015.

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 \$1.08 or 1.3% 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 and Phase 3 MATS Compliance Plans are approved. We find that the updated environmental plans, construction cost estimates and updated in-service dates for the various projects, including changes described in the testimony of Mr. Miller, are reasonable and approved.

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 October 31, 2014. The Presiding Officers granted the Motion in a November 13, 2014 Docket Entry, finding the information should be held confidential on a preliminary basis.

The Affidavits of Mr. Miller, Ms. Douglas, and Mr. McCallister indicate that the 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 the confidential information is trade secret and exempt from public access and disclosure by the Commission.

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 June 30, 2014, is approved, including the adjustments made to the allocations for certain industrial customers. 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 June 30, 2014, and estimated amounts for July 1, 2014, through December 30, 2014, related to its NOx Compliance Plan, Phase 1 CAIR/CAMR Compliance Plan, Gallagher DSI Projects, and capital maintenance, as reflected in the exhibits and testimony of Duke Energy Indiana, is approved, including the amortizations of the Phase 2 and Phase 3 MATS Compliance Plan development costs, post-in-service carrying costs accrued on the Gallagher DSI Projects, and adjustments made to the allocations for certain industrial customers. 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 this Order.

3. Petitioner's proposed updated Rider 63, including reconciliation through August 2014, and estimated EA costs for March 2015 through August 2015, as reflected in the direct exhibits and testimony of Duke Energy Indiana, is 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 March 2015.

4. Petitioner's ongoing review progress reports related to its NOx, Phase 1 CAIR/CAMR, Phase 2 and Phase 3 MATS Compliance Plans, and the Gallagher DSI Projects are approved.

5. Petitioner's updated environmental plan, cost estimates, and estimated in-service dates for its NOx, Phase 1 CAIR/CAMR, and Phase 2 and Phase 3 MATS Compliance Plan projects are 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 in this proceeding are found to be trade secret and therefore excepted from public access.

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

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

FEB 11 2015

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



Brenda A. Howe
Executive Secretary to the Commission