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STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF DUKE ENERGY INDIANA, INC. SEEKING AUTHORITY TO REFLECT ADDITIONAL VALUES OF QUALIFIED POLLUTION CONTROL PROPERTY UNDER CONSTRUCTION IN ITS RATES THROUGH ITS STANDARD CONTRACT RIDER NO. 62, PURSUANT TO IND. CODE SECTIONS 8-1-2-6.6, 8-1-2-6.8 AND 170 I.A.C. 4-6-18; SEEKING APPROVAL OF AN ONGOING REVIEW PROGRESS REPORT CONCERNING CERTAIN CLEAN COAL TECHNOLOGY PROJECTS PURSUANT TO IND. CODE SECTION 8-1-8.7-7; SEEKING APPROVAL OF AN UPDATED COMPLIANCE PLAN, UPDATED COST ESTIMATES AND ESTIMATED IN-SERVICE DATES FOR ENVIRONMENTAL PROJECTS; SEEKING APPROVAL OF AN ADJUSTMENT TO ITS RATES THROUGH ITS CLEAN COAL OPERATING COST REVENUE ADJUSTMENT STANDARD CONTRACT RIDER NO. 71, IN ACCORDANCE WITH IND. CODE SECTION 8-1-8.8-11; AND SEEKING APPROVAL OF AN ADJUSTMENT TO ITS RATES THROUGH ITS SO_2, NO_X AND Hg EMISSION ALLOWANCE ADJUSTMENT, STANDARD CONTRACT RIDER NO. 63	)	CAUSE NO. 42061 ECR 20 APPROVED: FEB 13 2013

ORDER OF THE COMMISSION

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

On October 26, 2012, Duke Energy Indiana, Inc. ("Petitioner," "Company" or "Duke Energy Indiana") filed a Petition with the Indiana Utility Regulatory Commission ("Commission") seeking: (1) to reflect additional values of qualified pollution control property ("QPCP") in its rates and charges for electric service, through Standard Contract Rider No. 62 ("Rider 62"); (2) approval of an ongoing review progress report concerning certain clean coal technology projects; (3) approval of an updated compliance plan, updated cost estimates and in-service dates for environmental projects; (4) approval of an adjustment to its rates through its Clean Coal Operating Cost Revenue Adjustment mechanism, Standard Contract Rider No. 71 ("Rider 71"); and (5) approval of an adjustment to its rates through its sulfur dioxide ("SO_2"), nitrogen oxide ("NOx") and mercury ("Hg") Emission Allowance Adjustment, Standard Contract Rider No. 63 ("Rider 63").

Pursuant to notice published as required by law, proof of which was incorporated into the record, an Evidentiary Hearing was held in this case on January 10, 2013 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. Edward O. Abbott. 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 general public appeared at the hearing.

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

1. <u>Notice and Jurisdiction</u>. 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 within the meaning of Ind. Code § 8-1-2-1 and is subject to the jurisdiction of the Commission, in the manner and to the extent provided by the laws of the State of Indiana. Petitioner requests relief pursuant to Ind. Code §§ 8-1-2-6.6, 8-1-2-6.8, 8-1-2-42(a), Ind. Code chs. 8-1-8.7 and -8.8, and 170 IAC 4-6. The Commission has jurisdiction over Petitioner and the subject matter of this proceeding.

2. <u>Petitioner's Characteristics</u>. 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. <u>Petitioner's Electric Generating Properties</u>. As of the date Petitioner filed testimony in this Cause, Petitioner's electric generating properties consisted of: (1) steam capacity located at four stations comprised of fourteen coal-fired generating units supplied by fourteen coal-fired boilers; (2) combined cycle capacity comprised of three natural gas-fired Combustion Turbines ("CT") and two steam turbine-generators; (3) a run-of-river hydroelectric generation facility comprised of three units; (4) peaking capacity consisting of seven oil-fired diesels located at two stations, seven oil-fired CT units located at two stations, and twenty-four natural gas-fired CTs, one of which has oil back-up.

4. <u>Background to this Proceeding</u>.

a. <u>NOx SIP Call</u>. 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 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).

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 CAIR on November 1, 2006.[1] 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 CAMR on October 3, 2007.[2]

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

[1] On July 11, 2008, the U.S. Court of Appeals for the D.C. Circuit in *State of North Carolina v. Environmental Protection Agency* issued an 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 ("CAIR Decision"). On July 6, 2011, the EPA finalized the Cross State Air Pollution Rule ("CSAPR"), with subsequent proposed revisions issued on October 6, 2011. On August 21, 2012, the D.C. Circuit Court vacated CSAPR in its entirety and directed EPA to continue administering CAIR pending completion of a valid replacement rule. On October 5, 2012, the EPA filed a petition seeking en banc rehearing of the D.C. Circuit Court's August 21, 2012 decision regarding CSAPR. The U.S. Court of Appeals for the D.C. Circuit issued an order denying rehearing on January 24, 2013.

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

c. **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 resolving New Sourt Review litigation ("Consent Decree"), Petitioner agreed to install and operate a dry sorbent injection system ("DSI System") on Gallagher Units 2 and 4 (the "Gallagher DSI Projects"). On September 8, 2010, in Cause No. 43873, the Commission granted a CPCN to Petitioner for the use of the Gallagher DSI Projects, approved the estimated costs for the projects, and found that the Gallagher DSI Projects constituted "Clean Coal Technology" as that term is defined in Ind. Code ch. 8-1-8.7. On December 28, 2011, in Cause No. 43956, the Commission granted Petitioner authority to include the Gallagher DSI Projects in its QPCP and to recover a return on the capital expenditures for the Gallagher DSI Projects through Rider 62 and to recover the incremental operation and maintenance ("O&M") expenses (including the cost of reagents and depreciation) of the Gallagher DSI Projects through Rider 71.

d. **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 proceedings.

5. **Relief Sought in this Proceeding.** In this six-month update proceeding, Petitioner requests the authority to reflect additional values of QPCP, as of June 30, 2012, in its rates and charges for electric service. 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 Rider (including approval of a credit to customers of the amount of incremental demand revenues under contracts with Nucor Corporation and Temple-Inland); and (4) an update and adjustment to Petitioner's SO_2, NOx and Hg Emission Allowance Adjustment Rider.

6. **Statutory and Regulatory Framework.**

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

b. **CWIP Statute and Administrative Rules.** 170 IAC 4-6-4 provides that the Commission shall approve the use of QPCP if it consists of one or more air pollution control devices, the devices meet applicable state or federal requirements, the devices are designed to accommodate the burning of coal from the geological formation known as the Illinois basin, and the estimated costs of construction and installation are reasonable. Once pollution control equipment is found to be QPCP, then the utility is allowed to add the value of the QPCP to the value of the utility's property for ratemaking purposes. *See* 170 IAC 4-6-5; Ind. Code §§ 8-1-2-

6.6, and 6.8. Per the Commission's CWIP rules, CWIP ratemaking treatment is available for QPCP that has been under construction for six months or longer, and a utility can update the amounts of its CWIP balances no more often than every six months. *See* 170 IAC 4-6-9 and -18.

c. Utility Generation and Clean Coal Technology Statute, Ind. Code ch. 8-1-8.8 (also referred to as "Senate Bill 29"). 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., Director, Strategic Engineering, Duke Energy Business Services LLC; Ms. Diana L. Douglas, Director, Rates, Duke Energy Business Services LLC; Mr. Joseph F. McCallister, Director, Gas Oil and Power, Progress Energy Carolinas; and Mr. Edward O. Abbott, Consulting Engineer, Monitoring & Diagnostics Center.

a. Compliance Plan Progress Reports. Mr. Miller stated that Petitioner is constructing its NOx Compliance Plan projects in order to comply with federal and state NOx SIP Call regulations that took effect in May 2004 and is constructing its CAIR/CAMR 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 19 ("ECR 19"), the most recent six-month update case.

Additionally, Mr. Miller reiterated that the estimated costs of the NOx Compliance Plan have remained reasonably accurate, although as with any multi-year plan there are ongoing impacts and refinements that could potentially affect costs. He further added that with the Commission's approval, for CWIP ratemaking purposes, the Petitioner proposes to include the actual costs of the projects once they are known, whether higher or lower than the original estimates. Mr. Miller testified Petitioner's estimated costs for its NOx Compliance Plan reflect decreases in the estimated costs for the replacement catalyst beds planned through 2022. Mr. Miller also noted that although several of the NOx projects are in-service,[3] that does not mean additional construction dollars will not be spent or recorded on the project (*i.e.* painting, tuning, testing, etc.).

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

Mr. Miller explained that in order to avoid confusion, since the Company's last filing in ECR 19, his Exhibit A-1 has been revised to remove the projects that had been deferred or cancelled due to Petitioner's pending Phase 2 Environmental Compliance Plan in Cause No. 44217.

Mr. Miller testified that the only projects added to the Company's CAIR/CAMR Compliance Plan since the Settlement Agreement in Cause Nos. 42622 and 42718 have been the addition of mercury emission monitors that were under construction or purchased by the time CAMR was vacated. Mr. Miller testified the mercury monitors at Gibson Station were either installed or almost completely installed at that time. The Company completed the installation of the Gibson Station monitors and one monitor at Gallagher Station, and placed the remainder of the purchased monitors in storage. Mr. Miller testified that in anticipation of the then-pending Mercury Air Toxics Standards ("MATS") rule, the Company removed the Cayuga Station monitors from storage and installed those monitors in 2011. The Company is currently operating some of the already installed monitors at Gibson Station and Cayuga Station to learn more about how this equipment operates and to collect more data about the Company's actual mercury emissions from these units to help with compliance planning.

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

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

Mr. Miller explained that in order to avoid confusion, since the Company's last filing in ECR 19, his Exhibit A-2 has been revised to remove the projects identified as "Phase II" projects due to Petitioner's pending Phase 2 Environmental Compliance Plan in Cause No. 44217.

Mr. Miller discussed the status of Petitioner's Gallagher Units 2 and 4 compliance projects that were part of the Consent Decree. The Company received a CPCN to install and operate the DSI System 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 DSI System through its environmental cost recovery rider.

Mr. Miller provided the Company's 2012 annual progress report on the DSI System stating that construction and testing of both DSI Systems on Units 2 and 4 were substantially complete in 2010 and that Duke Energy Indiana has been able to maintain the required sulfur limits. Mr. Miller further stated that the cost estimates of the DSI System, since the Company's 2011 progress report, remain the same and that the Company is continuing to evaluate the need for ash fixation in the landfill as a result of operating the DSI System. He testified the cost estimate for the required equipment remained reasonable.

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 (calculated consistent with the Commission's CWIP rules). Specifically, Ms. Douglas provided information establishing the incremental value of QPCP investment through June 30, 2012 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 Projects for which Petitioner is seeking recovery; showed the computation of the jurisdictional revenue requirement associated with that investment; and determined the allocation of the jurisdictional revenue requirement to various retail customer groups. Ms. Douglas explained that consistent with the Commission's Order in consolidated Cause Nos. 41744 S1 and 42061 and subsequent related Orders, the QPCP projects will be deemed to be under construction, and Petitioner will continue to receive revenues through Rider 62, until the Commission determines that these projects are used and useful in a proceeding that involves the establishment or investigation of Petitioner's base rates and charges, or until these projects no longer satisfy the other requirements of the Commission's CWIP ratemaking rules.

Ms. Douglas explained that her Rider 62 exhibits reflect the removal of deferred or cancelled projects as well as the proposed Phase II projects, in order to eliminate any confusion, due to the Company's Phase 2 Environmental Compliance Plan, which is pending before this Commission in Cause No. 44217.

Ms. Douglas testified regarding the retirement of certain equipment that has been replaced as part of capital maintenance projects and explained how the Company reflected these retirements in Rider 62. She explained that the retirements have been accounted for on the Company's accounting books and records pursuant to U.S. Generally Accepted Accounting Principles ("GAAP").

Ms. Douglas also explained the costs associated with capital maintenance projects affiliated 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. She described the term capital maintenance and how the Company classifies its property pursuant to the Federal Energy Regulatory Commission's ("FERC") Uniform System of Accounts, and how the Company determines whether a property unit must be capitalized.

Mr. Abbott discussed the capital maintenance projects for which costs, incurred after June 30, 2011, have been included. Mr. Abbott explained the following twelve capital maintenance projects, of which six were in service and six were still in progress, related to QPCP under the approved NOx and Phase 1 CAIR/CAMR Compliance Plans for which Petitioner seeks recovery:

Project	NOx or Phase 1 QPCP	Completion Status
Cayuga 1 Absorber Recirculating Pump Motor Rewind	FGD[4]	In Service
Gallagher 2 Baghouse Bag Replacement	Baghouse	In Service
Gibson 1-5 Soda Ash Pumps	SCR[5]	In Progress
Soda Ash Tank Platform/Vent/Insulation	SCR	In Progress
Gibson 3 SCR SBS Probes	SCR	In Service
Gibson 1-3 FGD Service Water Strainer	FGD	In Service
Gibson 1 SCR NOx Monitor Control System	SCR	In Progress
Gibson 5 SCR NOx Monitor Control System	SCR	In Progress
Cayuga 2 FGD EJ6 and EJ7 Replacement	FGD	In Service
Cayuga 2 ABS Recycle Pump Impellors	FGD	In Progress
Gibson 3 FGD 3-3 AR Pump Impellor	FGD	In Service
Gibson 1-3 FGD OX Air Humidity Water Source	FGD	In Progress

Additionally, Mr. Abbott testified about other future maintenance projects, such as the replacement of the absorber recycle pump impellors and gearboxes on FGD equipment at Gibson Station.

Ms. Douglas explained the inclusion of costs associated with the Gallagher DSI System, which were further discussed by Mr. Miller.

Ms. Douglas testified that the federal income tax rate used in the calculation of the jurisdictional revenue requirement was not adjusted to reflect a tax deduction under the Internal Revenue Code Section 199 provided for in the American Jobs Creation Act of 2004 because the Company is not expected to be allowed to take the deduction in 2013 (when the factors developed in this filing will be billed to customers) due to its expected tax position after reflecting bonus depreciation for the Edwardsport plant. The power block portion of the Edwardsport plant was declared to be in-service for tax purposes as of August 1, 2012, and produced bonus depreciation that prevented the deduction under Internal Revenue Code Section 199. She explained that the remainder of the plant is expected to be declared in-service for income tax purposes in 2013.

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.

[4] Flue Gas Desulfurization
[5] Selective Catalytic Reduction

Ms. Douglas stated that with the proposed CWIP ratemaking treatment and proposed rates, the monthly bill of a typical residential customer using 1,000 kilowatt-hours would decrease by three cents, or 0.04%, when compared to the last approved factor (excluding other various tracking mechanisms).

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, 2012, and the estimated costs for the period July through December 2012.

Mr. Abbott testified that the projects having incremental O&M expenses associated with the Company's NOx SIP Call Compliance Plan are the Gibson Station Units 1-5 SCRs, Gibson Station Units 1-5 arsenic mitigation system, and the Gibson Station Units 1-5 sulfur trioxide mitigation systems. He stated the incremental costs will fluctuate based on demand and the generation level of the units. Mr. Abbott also testified regarding the incremental O&M expenses associated with the Company's CAIR Compliance Plan. He explained the projects associated with these expenses are the Cayuga Units 1 and 2 FGDs, Gibson Station Units 1-3 FGDs, Gibson Station Units 4 and 5 FGD upgrades, and Gallagher Units 1-4 baghouses.[6] 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. Abbott explained the incremental O&M expenses associated with the Gallagher Units 2 and 4 DSI System. Again, he stated the incremental costs associated with this project 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, the Company retired Gallagher Units 1 and 3 at the end of January 2012. She explained 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 projects and the Phase 1 CAIR/CAMR Compliance Plan projects. Ms. Douglas further explained that both the Company's capital maintenance projects and Gallagher DSI Projects are being depreciated using the most recently Commission-approved depreciation rates based on the FERC accounts associated with the property.

In addition, 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 2013 demand revenues applicable to Nucor's interruptible load and a reconciliation of the credit applicable to January through June 2012 was included in the development of the revenue requirement used in developing the Clean Coal Operating Cost Revenue Adjustment Factors. The Nucor Credit was calculated in accordance with the Commission's Order in Cause No. 43754 and its Order in Cause No. 42061 ECR 15 ("ECR 15") using the revenue requirements

[6] Gallagher Units 1 and 3 were shut down at the end of January 2012, in accordance with the order in Cause No. 43956.

proposed in this ECR 20 proceeding for both Rider 62 and Rider 71 (excluding the Nucor Credit and Temple-Inland Credit) and the revenue requirements from the most recently approved Rider 61 (Cause No. 43114 IGCC 4, which was approved by the Commission on July 28, 2010). Ms. Douglas testified that the Temple-Inland Credit was calculated in accordance with the Commission's Order in Cause No. 44087 and its Order in ECR 15 (related to the Nucor credit) using actual steam demand for the period February through June 2012 with the revenue requirements proposed in this proceeding for Riders 62 and 71 (excluding the Nucor Credit and Temple-Inland Credit).[7] She further explained that Petitioner planned to include credits representing six months' worth of apportioned Nucor and Temple-Inland demand revenues in future ECR proceedings until such time as Nucor and Temple-Inland demand revenues have been included in new base rates approved by the Commission in Petitioner's next retail base rate case.

Ms. Douglas also explained that Petitioner pledged to return the difference between the property tax expense approved in Cause No. 42359 and actual jurisdictional property tax expense, if lower. Ms. Douglas testified that the estimate for the 2013 expense appears to well exceed the amount in base rates and the tracking of property tax expense under Rider 62 will not be necessary for this or succeeding tax years. However, Ms. Douglas testified that, for administrative convenience, the remaining $1,366,000 refund due to customers for the expense for tax years 2010 and 2011 is proposed to be included in the calculation of the Rider 71 rates to effectuate a full refund of this amount in ECR 20. She also stated that because Rider 71 was designed to reconcile all items included in the rider, the inclusion of the refund amount in Rider 71 will enable Petitioner to more quickly refund the amount to customers as it looks toward what appears to be the end of the required tracking of property taxes. She stated Duke Energy Indiana will continue to report on the estimated and final amounts, and if any additional adjustments are needed, they will be included in Rider 71.

Ms. Douglas indicated that the monthly bill of a typical residential customer using 1,000 kilowatt-hours would increase by approximately thirty-eight cents, or approximately 0.5% when compared to the last approved factor (excluding other various tracking mechanisms).

d. <u>Rider 63</u>. Finally, Ms. Douglas explained and supported Petitioner's proposed adjustments to Rider No. 63, covering the reconciliation of SO_2 and NOx net EA expenses versus the net expenses incurred for the six months ended August 31, 2012, and the estimated NOx and SO_2 EA costs for the period March through August 2013. Ms. Douglas stated the proposed EA cost recovery on a monthly bill of a typical residential customer using 1,000 kilowatt-hours (excluding the effect of various "tracking mechanism"), will increase by $0.17, when compared to the last approved factor. She explained that when compared to the factor in place for March 2012 through August 2012, this typical residential customer will see an increase of $0.15 or 0.2%. Ms. Douglas testified that this factor included realized gains from the EPA's annual SO_2 auction. She further testified that no estimates were included of EA sales during the projected period.

Mr. McCallister explained the vacature and current status of CSAPR impact on the CAIR programs, CAIR allowances in inventory and compliance. He stated that in October 2012, EPA returned the vintage 2013 CAIR Annual and Seasonal NOx allowances because CAIR is

[7] Rider 61 is not applicable to the Temple-Inland steam contract.

anticipated to remain in place with the 2013 seasonal and annual NOx requirements. Mr. McCallister further explained that while CAIR is in effect, SO_2 compliance will take place under the CAIR rules using the compliance ratio[8] mandated by CAIR and that the ratio is increasing. Mr. McCallister concluded that given the vacature and assuming CAIR is in place for the 2013 compliance period, the Company will have to comply with the requirements of CAIR Annual NOx, CAIR Seasonal NOx, and Title IV/Acid Rain SO_2 using the CAIR SO_2 ratio requirements.

Mr. McCallister described the trading market for CAIR EAs. He stated that since the vacature of CSAPR in August 2012 and the return of the 2013 vintage CAIR allowances to the accounts, market activity for CAIR allowances continues to be limited and CAIR market prices remain at or near levels observed when the expectation was for CSAPR to replace CAIR. He also explained that market activity for CSAPR EAs has been very limited.

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 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 also explained that the model distinguishes between native load EA requirements and EAs to support non-native sales, and that the inventories are managed separately. He stated once a purchase is made for native load, those EAs remain with native load, and similarly for purchases made for non-native load. Further, 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 the EPA are valid in later years, Petitioner must also consider the Company's position in later years.

Mr. McCallister explained that, based on the current forecasting period in CAIR SO_2, seasonal and annual NOx EAs, Petitioner projects it will have more allowances in inventory required for compliance through 2015. Mr. McCallister testified 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. He further explained that the Company continues to assess the EA market and developments in the CSAPR litigation, looking for ways to optimize the EA positions by using the EA market to buy and sell EAs, as needed, passing through to customers the costs of purchases and the gains or losses on sales in the normal course of business. Mr. McCallister opined that the Company purchases and sells EAs in an open and active market to provide energy to native load customers as economically as possible.

[8] The compliance ratio is the number of SO_2 EAs that must be surrendered to comply with 1 ton of SO_2 emissions.

Mr. McCallister testified that there were no EA sales in the reconciliation months for this proceeding. He further stated he provided information with respect to the Company's estimated EA consumption for Ms. Douglas to use for updating estimated EA costs for the forecast months. He stated these forecasts are based on the same modeling the Company has used for a number of years.

8. **Summary of the OUCC's Evidence.** Mr. Wes R. Blakley, Senior Utility Analyst for the OUCC, testified that he reviewed Petitioner's filings in this Cause and the Commission's Order in ECR 19 and nothing came to his attention that would indicate Petitioner's calculation of the 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 the Company has requested recovery of costs associated with the Gallagher DSI Projects and a recalculation of depreciation expense related to the pollution control assets at retired Gallagher Units 1 and 3. Mr. Blakely described Petitioner's proposed apportionment of the revenue from the Nucor demand charge to the impacted riders and noted that the total amount is reflected in Rider 71 to avoid a separate adjustment for all three impacted riders. He further noted a credit for a similar arrangement with Temple-Inland was reflected in the Rider 71 net revenue requirement. Mr. Blakley also noted the testimony of Ms. Douglas and Mr. Abbott regarding capital maintenance projects.

Ms. Cynthia M. Armstrong, Utility Analyst in the Electric Division for the OUCC, testified that she had reviewed Petitioner's filings in this Cause. Ms. Armstrong testified that Petitioner's calculation of EA adjustments was accurately applied and that since the only sale of EAs was due to the mandatory EPA Allowance Auction, the OUCC did not conduct an audit of the Company's EAs for this proceeding. Ms. Armstrong recommended that in future ECR proceedings the Company provide more specific details on why specific costs within its approved environmental compliance plans have increased. She noted that detailed reasons for construction cost increases are important in order for the Commission to determine whether increases in Clean Coal Technology costs beyond the approved CPCN amount are reasonable and necessary under the ongoing review process set forth under Ind. Code § 8-1-8.7-7. She stated that due to the expedited nature of the ECR proceedings, it is important for the Company to provide this information at the time it files its testimony. She noted that Duke Energy Indiana did provide explanations for the cost increases, and attached a copy of those explanations.

9. **Commission Discussion and Findings.** Based upon the evidence presented, the Commission finds that Petitioner's request should be approved. Specifically, the Commission finds that Petitioner should be authorized to reflect the additional values through June 30, 2012 of the NOx Compliance Plan, the Phase 1 CAIR/CAMR Compliance Plan, Gallagher DSI Projects and related capital maintenance projects in its rates and charges for electric service in accordance with Duke Energy Indiana's Rider 62, as indicated in the direct testimony and exhibits of Ms. Diana L. Douglas.

Petitioner should be authorized to recover its O&M and depreciation expenses related to its NOx Compliance Plan, Phase 1 CAIR/CAMR Compliance Plan, Gallagher DSI Projects and capital maintenance projects, in accordance with Duke Energy Indiana's Rider 71, as described in the testimony and exhibits of Ms. Douglas, including the reconciliation of such expenses for the period January through June 2012, and the estimated amounts for the period July through December 2012.

Petitioner should also be authorized to recover its SO_2 and NOx EA costs in accordance with Duke Energy Indiana's Rider 63, as described in the direct testimony and exhibits of Ms. Douglas, including the reconciliation of such expenses for the period March through August 2012 and the estimated amounts for the period March through August 2013.

The combined impact of the proposed factors for Standard Contract Riders 62, 63 and 71 for a typical residential customer using 1,000 kilowatt-hours is an increase of $0.53 or 0.6% when compared to the last approved factors.

In addition, Petitioner's ongoing review progress report related to its NOx Compliance Plan, Phase 1 CAIR/CAMR Compliance Plan, and the Gallagher DSI Projects is hereby approved. We find that the updated construction cost estimates and updated in-service dates provided by Petitioner in this Cause are reasonable and are hereby approved as such.

Finally, the Commission finds the OUCC's recommendation that Petitioner provide more specific details on why particular costs within its approved environmental compliance plans have increased to be reasonable and orders Petitioner to provide such information in future ECR proceedings.

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 November 8, 2012. In this Motion, Petitioner demonstrated a need for confidential treatment for the detailed cost estimates associated with Petitioner's environmental compliance plan, unit-specific operation and maintenance costs, specific EA transaction prices, certain load and price information concerning a confidential Commission approved special contract with Nucor Steel, certain price information for a confidential Commission approved special contract with Temple-Inland, and certain retirement detail that contains actual costs. In a November 15, 2012 Docket Entry, the Commission preliminarily found that such information should be subject to confidential procedures.

The Affidavits of Mr. Miller, Ms. Douglas and Mr. McCallister indicate that such confidential information has actual or potential independent economic value for Petitioner and its ratepayers, the disclosure of the confidential information could provide Petitioner's competitors and suppliers an unfair advantage, and Petitioner and its affiliates have taken all reasonable steps to protect the confidential information from disclosure. Accordingly, pursuant to Ind. Code §§ 5-14-3-4(a)(4) and 8-1-2-29, we find that the detailed cost estimates are "trade secrets" and should be afforded confidential treatment.

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

1. Petitioner's proposed updated Rider 62, as reflected in the direct exhibits and testimony of Duke Energy Indiana, including QPCP values as of June 30, 2012, is hereby approved. The Rider 62 shall go into effect upon the filing of the final Rider with the Commission's Electricity Division for all bills rendered after the effective date of this Order.

2. Petitioner's proposed updated Rider 71, as reflected in the exhibits and testimony of Duke Energy Indiana, is hereby approved. The Rider 71 shall go into effect upon the filing of the final Rider with the Commission's Electricity Division for all bills rendered after the effective date of the Commission's Order in this proceeding.

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

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

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

6. The detailed cost estimate information, unit-specific operation and maintenance costs, specific EA transaction prices, Temple-Inland price information, Nucor interruptible service detail, 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. In future ECR proceedings, Petitioner shall provide specific details concerning any particular costs within its approved environmental compliance plans that may have increased since Petitioner's last filing.

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

ATTERHOLT, BENNETT, LANDIS, MAYS, AND ZIEGNER CONCUR:
APPROVED: FEB 13 2013

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