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 19** **APPROVED:** AUG 29 2012

ORDER OF THE COMMISSION

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

On April 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 updated environmental projects, 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 ("NO_x") 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 July 26, 2012 at 9:30 a.m. in Room 222, 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. John P. Griffith, 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. On July 18, 2012, the Commission issued a Docket Entry requesting responses from Petitioner. Petitioner responded to the Commission Docket Entry on July 24, 2012. The response was offered and admitted into the evidentiary record without objection. No members of the public appeared or sought to testify at the hearing.

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

1. **Notice and Jurisdiction.** Due, legal and timely notice of the Evidentiary Hearing in this Cause was given and published by the Commission as required by law. Petitioner is a public utility within the meaning of the Public Service Commission Act, as amended, Ind. Code ch. 8-1-2, and is subject to the jurisdiction of the Commission, in the manner and to the extent provided by 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. **Petitioner's Characteristics.** Petitioner is a public utility organized and existing under the laws of the State of Indiana, and has its principal office at 1000 East Main Street, Plainfield, Indiana 46168. It is engaged in rendering electric utility service in the State of Indiana and owns, operates, manages, and controls, among other things, plant and equipment within the State of Indiana used for the production, transmission, delivery and furnishing of such electric service to the public.

3. **Petitioner's Electric Generating Properties.** As of the date 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[1]; (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.[2]

4. **Background to this Proceeding.**

a. **NO_x SIP Call.** The federal NO_x State Implementation Plan ("SIP") Call and related Indiana NO_x SIP Call required that Indiana reduce its NO_x emissions during the ozone

[1] As of January 31, 2012, Gallagher Units 1 and 3 were shut down. Therefore, there are fourteen coal-fired boilers in service at this time.
[2] Beginning January 12, 2012, Duke Energy Indiana began operating Vermillion Units 1-8.

season of May 1 through September 30 to a level of 0.15 lb/mmBtu by May 31, 2004. The reductions in NO_x 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 NO_x 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 NO_x Compliance Plan equipment; and (5) approved Rider No. 62 that allows for construction work in progress ("CWIP") ratemaking treatment for Petitioner's QPCP. We found that Petitioner may update the value of its QPCP for CWIP ratemaking purposes no more often than every six months. Additionally, we found that, under our ongoing review rules, Petitioner should submit, at least annually, a progress report detailing any revisions in its cost estimates or in the planned construction of its clean coal technology projects.

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

The final CAIR requires major SO_2 and NO_x emission reductions, established annual and seasonal NO_x trading programs, and set limitations on use of SO_2 emission allowances. The Indiana Air Pollution Control Board adopted the final CAIR on November 1, 2006.[3] The final CAMR provides regulatory authority for a mercury cap and trade program, with a mercury cap for 2010 set at 38 tons, and 15 tons in 2018. The Indiana Air Pollution Control Board adopted the CAMR on October 3, 2007.[4]

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, we: (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,

[3] On July 11, 2008, the U.S. Court of Appeals for the District of Columbia 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 practical effect of this ruling is 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. CSAPR places statewide caps on overall SO_2 and NO_x power plant emissions in 2012 and 2014, and replaces CAIR starting January 1, 2012. However, on December 30, 2011, the D.C. Circuit stayed CSAPR and ordered that CAIR remain in effect while CSAPR is under review. The D.C. Circuit vacated CSAPR on August 21, 2012, and ordered that CAIR remain in effect pending EPA's promulgation of a replacement for CSAPR.

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

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. 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 (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 NO_x 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 December 31, 2011, 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 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 a contract with Nucor Corporation ("Nucor"), which has been apportioned to Riders 61, 62, and 71); and (4) an update and adjustment to Petitioner's SO_2, NO_x 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 Evidence.** Petitioner presented case-in-chief testimony and exhibits of Mr. Joseph A. Miller, Jr. General Manager, Analytical & Investment Engineering, Ms. Diana L. Douglas, Director, Rates, Mr. John P. Griffith, Director, Portfolio Optimization, Fuel and Emissions, and Mr. Edward O. Abbott, Consulting Engineer, Performance & Measures.

Mr. Miller stated Petitioner is constructing its NO_x Compliance Plan projects in order to meet federal and state NO_x 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 NO_x Compliance Plan is continuously changing and indicated that the current NO_x Compliance Plan is not significantly different from the plan presented in Cause No. 42061 ECR 18, the most recent six-month update case.

Additionally, Mr. Miller reiterated that the estimated costs of the NO_x 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, Petitioner proposes to include the actual costs of the projects once they are known, whether higher or lower than the original estimates. Mr. Miller also testified that the NO_x SIP Call Compliance Plan cost estimates that were previously approved remain valid, taking into account the adjustments as previously recorded. Overall, Petitioner's estimated costs for its NO_x Compliance Plan have increased slightly, reflecting certain cost increases on the replacement catalyst beds planned through 2022.

Mr. Miller testified that the only projects added to the Company's CAIR/CAMR compliance plan since the Settlement Agreement in Cause Nos. 42622/42718 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 pending maximum achievable control technology ("MACT") rules, the Company removed the Cayuga Station monitors from storage and installed those monitors in 2011. The Company is currently operating some of the already installed monitors at Gibson Station and the monitors at Cayuga Station to learn more about how the 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 impact and refinements as a normal part of an ongoing construction program. He added that Petitioner expects these costs to continue to be refined to a small degree. Overall, Petitioner's estimated costs for its CAIR/CAMR Compliance Plan have decreased slightly.

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

Mr. Miller discussed the status of the Gallagher DSI Projects and provided the Company's 2012 annual progress report on the DSI System. He stated 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 of whether ash fixation in the landfill is necessary as a result of operating the DSI System.

Ms. Diana L. Douglas, Director, Rates, described the proposed implementation of CWIP ratemaking treatment via Rider 62, and provided the schedules and information required by 170 IAC 4-6-12. Specifically, Ms. Douglas provided information establishing the incremental value of QPCP investment through December 31, 2011 for the approved NO_x 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.

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. In addition, she explained that depreciation of an asset on the accounting books stops upon retirement. The Company has reflected this in the actual and estimated depreciation amounts included in this filing, based on the dates the equipment was retired.

Ms. Douglas explained her new exhibit detailing the costs associated with capital maintenance projects, which were approved by the Commission in ECR 18 for recovery in Riders 62 and 71. Ms. Douglas described the term capital maintenance and how the Company classifies its property pursuant to the Federal Energy Regulatory Commission's ("FERC") Uniform System of Accounts, and how the Company determines whether a property unit must be capitalized.

Mr. Edward O. Abbott, Consulting Engineer, Performance & Measures, discussed the capital maintenance projects for which costs incurred after June 30, 2011 have been included. Mr. Abbott explained the following six capital maintenance projects, related to QPCP under the approved NO_x and Phase 1 CAIR/CAMR Compliance Plans for which Petitioner seeks recovery:

Project	NO_x or Phase 1 QPCP	Completion Status
Cayuga 1 Absorber Recirculating Pump Motor Rewind	FGD[5]	In Service
Gallagher 2 Baghouse Bag Replacement	Baghouse	In Service
Gibson 1-5 Soda Ash Pumps	SCR[6]	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

Additionally, Mr. Abbott testified about other maintenance projects expected in the near future. These projects include 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 discussed by Mr. Miller.

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[5] Flue Gas Desulfurization

[6] Selective Catalytic Reduction

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 ("Jobs Creation Act") because the Company is not expected to be allowed to take the deduction in 2012 (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 IGCC plant. Ms. Douglas explained this tax treatment further in response to the Commission's July 18, 2012 Docket Entry. In her response, she explained further that Duke Energy Indiana continues to evaluate whether any bonus depreciation related to the Edwardsport IGCC plant will be reflected in 2012. She testified that the Company's expectation at this time is that if the natural gas portion of the plant were put into service for federal income tax purposes in 2012, the bonus depreciation that would be reflected in 2012 would cause a net operating loss for Duke Energy Indiana which would prevent the recognition of the deduction under the Jobs Creation Act. She explained that it is not unusual for in-service dates for constructed assets to be different for income tax purposes than for financial or regulatory accounting purposes. Ms. Douglas stated that Duke Energy Indiana will notify the Commission in a future ECR proceeding when a definite determination has been made regarding the timing of the in-service date of the Edwardsport IGCC plant for income tax purposes.

Ms. Douglas also explained that Petitioner pledged to return the difference between the property tax expense approved in Cause No. 42359 and actual jurisdictional property tax expense, if lower. Ms. Douglas testified that based on this commitment, there is a net jurisdictional amount to be refunded to retail customers of $811,000.

Ms. Douglas testified regarding the Commission's Order in Cause Nos. 42908 and 43211, which approved the sale of Wabash River Unit 1 to WVPA and authorized the Company to apply revenues being recovered in current base rates for Wabash River Unit 1 to reduce the balance of the deferred costs that were not included in base rates for the Wheatland Plant, which the Company purchased in 2005. The Commission also ordered the Company to begin providing a credit to retail customers via Rider 62 once the balance of the deferred Wheatland Plant costs were fully offset, in an amount equal to the annual differential between avoided Wabash River Unit 1 costs and Wheatland Plant costs. Ms. Douglas stated that a credit was being included in the development of revenue requirements for the first time in this filing. The annual jurisdictional net savings to be refunded to customers via Rider 62 is $7,572,000.

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 approximately twenty-five cents, or 0.3%, when compared to the last approved factor (excluding other various tracking mechanisms).

Ms. Douglas also explained and supported Petitioner's proposed adjustments to Rider 71 covering the reconciliation of depreciation and O&M expenses billed versus depreciation and O&M expenses actually incurred for the six months ended December 31, 2011, (except in the case of the Gallagher DSI Projects depreciation and O&M, for which the Company is requesting to include costs for the calendar year 2011, since this is the first filing since the Commission's order approving recovery of these costs), and the estimated costs for the period January through June 2012. Ms. Douglas testified that the Company intends to use the most recently Commission-approved depreciation rates for the Gallagher DSI Projects and for the capital maintenance projects which the Company began including in this filing, rather than the accelerated depreciation rates that were approved for use for other equipment in this Rider.

Ms. Douglas explained that pursuant to the Consent Decree entered into by the Company and the Department of Justice resolving New Source Review litigation, Petitioner 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. Therefore, 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 that had been previously used for the NO_x Compliance Plan projects and the Phase 1 CAIR/CAMR Compliance Plan projects.

Ms. Douglas discussed the estimated depreciation expenses applicable to the capital maintenance projects associated with NO_x and Phase I CAIR/CAMR Compliance Plan Projects and the Gallagher DSI Projects for the period January through June 2012. She indicated the 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 2012 demand revenues applicable to Nucor's interruptible load ("the Nucor Credit"), and a reconciliation of the credit applicable to July through December 2011, 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 using the revenue requirements proposed in this ECR 19 proceeding for both Rider 62 and Rider 71 (excluding the Nucor 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). She further explained that Petitioner planned to include credits representing six months' worth of apportioned Nucor demand revenues in each Rider 71 rate adjustment in future ECR proceedings until such time as Nucor demand revenues have been included in new base rates approved by the Commission.

Ms. Douglas indicated that the monthly bill of a typical residential customer using 1000 kilowatt-hours would increase by approximately twenty-two cents, or approximately 0.3% when compared to the last approved factor (excluding other various tracking mechanisms).

Finally, Ms. Douglas explained and supported Petitioner's proposed adjustments to Rider 63, covering the reconciliation of SO_2 and NO_x net emission allowance expenses versus the net expenses incurred for the six months ended February 29, 2012, and the estimated NO_x and SO_2 EA costs for the period September 2012 through February 2013. Ms. Douglas stated the monthly bill of a typical residential customer using 1,000 kilowatt-hours (excluding the effect of various tracking mechanisms), will decrease by $0.02, when compared to the last approved factor. She explained that when compared to the factor in place for July 2011 through February 2012, this typical residential customer will see a decrease of $0.19 or 0.3%.

Ms. Douglas testified the calculation of the conversion factor related to steam sales had changed since the filing in ECR 18 due to a recent amendment to the contract between Duke Energy Indiana and TIN Inc., doing business as Temple-Inland, which was approved by the Commission on January 25, 2012 in Cause No. 44087, and effective February 1, 2012. Ms. Douglas stated that this new conversion factor was used in the calculations of the actual EA cost factor for February 2012 and for the estimated EA cost factor for September 2012 through February 2013.

Ms. Douglas next explained that the Commission approved in its January 25, 2012 Order in Cause No. 42061 ECR 18 the Company's proposed change to implement the Rider 63 rates approved effective March 1, 2012, consistent with the forecast period. She stated that since the ECR 18 factor took effect March 2012 and the ECR 17 variance was fully reflected in the July through December 2011 reconciliation calculations, no prior variance amount needed to be included in the January and February 2012 reconciliation calculations. Ms. Douglas explained that this is a one-time situation due to the change in the timing of billing implementation.

Ms. Douglas testified that the factor does not include any charges or credits associated with EA sales. She further testified that no estimates were included of EA sales during the projected period. She referenced the testimony of Mr. Griffith, and his explanation that the Company's positions in CAIR SO_2, seasonal and annual NO_x EAs are longer than would be required and would normally be maintained due to uncertainty about environmental rules. However, once more certainty is obtained, the Company intends to return to its normal practice of maintaining balanced positions, including purchases and sales of emission allowances as needed. Ms. Douglas explained that when this occurs, Petitioner will include in the development of the EA adjustment factor in future ECR proceedings any gains or losses from such sales to rebalance the position.

Mrs. Douglas concluded that 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 would be a decrease by five cents or 0.1% when compared to the last approved factors.

Mr. John P. Griffith, Director, Portfolio Optimization, Fuel, and Emissions, explained that on July 11, 2008, the D.C. Circuit Court issued an opinion vacating and remanding CAIR. However, on December 23, 2008, the Court granted rehearing only to the extent that it remanded rules to the EPA without vacating them, intending that CAIR remain in place until EPA issued a new rule or rules in accordance with the July 11, 2008 decision. Mr. Griffith explained that on July 7, 2011, EPA finalized the Cross State Air Pollution Rule ("CSAPR"), with subsequent revisions issued on October 6, 2011. CSAPR created new SO_2, Seasonal NO_x and Annual NO_x emission programs beginning January 1, 2012. But, on December 30, 2011, the D.C. Circuit Court stayed CSAPR and ordered the CAIR program remain in effect while CSAPR was under review.[7]

[7] As noted earlier, the D.C. Circuit vacated CSAPR on August 21, 2012 and ordered that CAIR remain in effect pending EPA's promulgation of a replacement for CSAPR.

Mr. Griffith described the trading market for CAIR emission allowances. He stated that trading in the CAIR programs has continued, but volumes have been low and liquidity has been poor and that market conditions continued to deteriorate after CSAPR was finalized and into 2012, despite the program being extended for 2012. Mr. Griffith went on to describe the market for CSAPR emission allowances. He stated that the first CSAPR transactions took place in late August 2011 and that activity increased in September and October 2011, until it became apparent that CSAPR would face legal challenges and possible delays. He further explained that since CSAPR was stayed, trading in the CSAPR markets has been infrequent and market transparency is poor.

Mr. Griffith testified regarding other SO_2 compliance issues also on the horizon. He stated that the compliance ratio[8] is increasing under the CAIR rules. He explained that for the 2010 to 2014 vintages, two EAs must be surrendered for each ton of SO_2 emitted. Effective with vintage 2015 SO_2 EAs, 2.86 EAs must be surrendered for each ton of SO_2 emitted. However, the compliance ratio for SO_2 EAs of vintage 2009 or earlier doesn't change. Under the current rules only one SO_2 EA of vintage 2009 or earlier must be surrendered for each ton of SO_2 emitted. Mr. Griffith stated that the increase of the compliance ratio decreases the effectiveness of Duke Energy Indiana's allocation of SO_2 EAs from the EPA, which may contribute to increasing compliance costs as long as CAIR remains in effect.

Mr. Griffith explained it is anticipated that once CSAPR takes effect, Duke Energy Indiana will have to comply with four emission programs: CSAPR Annual NO_x, CSAPR Seasonal NO_x, CSAPR SO_2, and Title IV/Acid Rain SO_2.

Mr. Griffith described the types of transactions that occur in the EA market and why it is necessary for Duke Energy Indiana to participate. Mr. Griffith described the sophisticated production costing model that Petitioner uses to determine whether the Company needs to purchase EAs or if the Company has a surplus and can sell some of its EA inventory. According to Mr. Griffith, 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. Griffith 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. Griffith stated the model is just a tool, and that judgment must be applied to the output. Mr. Griffith explained the model distinguishes between native load EA requirements and EAs to support non-native sales, and the inventories are managed separately. He stated that once a purchase is made for native load, those EAs remain with native load, and similarly for purchases made for non-native load. Also, all zero cost allowances Petitioner receives are maintained for the benefit of native load customers.

Mr. Griffith explained that Petitioner's goal is to approach a balanced position plus a reserve of EAs for contingency and strive for balance on an annual basis. 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.

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[8] The number of SO_2 EAs that must be surrendered to comply with one ton of SO_2 emissions.

Mr. Griffith described the Company's current positions in regard to CAIR SO_2, seasonal and annual NO_x EAs stating that they are longer than would be required for compliance through the 2015 compliance period, but the Company believes that this reflects an appropriate level of caution about the uncertainty regarding future emissions requirements, implementation of CSAPR, and the phase-out of CAIR. Mr. Griffith testified that there continues to be uncertainty about the Company's EA positions given the effects of future power, coal and gas pricing on the Company's generation fleet, along with the legal uncertainty surrounding CAIR and CSAPR. Mr. Griffith further explained that the Company continues to assess the EA market and developments in the CSAPR litigation, in anticipation of a resolution to the litigation and the expectation of improved clarity for future emissions compliance under CAIR or under CSAPR. He explained Petitioner expects to be able to use the EA market to buy and sell EAs as needed to return to and maintain balanced EA positions, passing through to customers the costs of purchases and the gains or losses on sales in the normal course of business.

Mr. Griffith stated Petitioner makes purchases when it is projected to be short, and sells when projected to be long, and all transactions are conducted at the then current market prices for that vintage of EAs. He opined that the purchases and sales of native load EAs for the period have been conducted in a reasonable manner.

Mr. Griffith testified 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 months of September 2012 through February 2013. He stated these forecasts are based on the same modeling the Company has used for a number of years. However, the forecasted EA consumption used in this proceeding assumes that CSAPR will take effect January 1, 2013. Mr. Griffith testified that if, for some reason, these rules do not take effect on that date, the Company's EA consumption could be different, and actual EA costs for the forecasted period could be greater than the estimated costs used by Ms. Douglas to develop the rates in this proceeding.

Mr. Abbott testified that the projects having incremental O&M expenses associated with the Company's NO_x 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 these 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 Phase 1 CAIR/CAMR 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.[9] 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 concluded the incremental costs associated with this project are not fixed and will vary based on demand and the generation level of the units.

[9] As noted above, Gallagher Units 1 and 3 were shut down at the end of January 2012.

Mr. Wes R. Blakley, Senior Utility Analyst for the OUCC, testified that he had reviewed Petitioner's filings in this Cause, as well as from its previous filings 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 two items appear in this filing for the first time – a credit showing the difference between the 2007 sale of Wabash River Unit 1, which costs are embedded in current rates, and the deferred costs of the 2005 purchase of the Wheatland plant, which is not included in rates; and requested recovery of costs associated with the Gallagher DSI Projects, approved December 28, 2011 in Cause No. 43956. Mr. Blakley described Petitioner's proposed apportionment of the revenue from the Nucor Credit to the impacted riders and noted that the total amount is reflected in Rider 71 to avoid a separate adjustment for all three impacted riders. Mr. Blakley also 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, as well as from its previous filings. She also conducted a field audit to review detailed accounting material for randomly selected dates of emission allowance transactions and spoke to Duke Energy Indiana staff. Ms. Armstrong testified that Petitioner's calculation of emission allowance adjustments was accurately applied and Petitioner's emission allowance trades were reasonable.

8. Commission Discussion and Findings. Based upon the evidence presented, the Commission finds that Petitioner's request should be approved as set forth herein. Specifically, the Commission finds that Petitioner should be authorized to reflect the additional values through December 31, 2011 of the NO_x Compliance Plan, Phase 1 CAIR/CAMR Compliance Plan, Gallagher DSI Projects and related capital maintenance in its rates and charges for electric service in accordance with Rider 62, as indicated in the direct testimony and exhibits of Ms. Diana L. Douglas, subject to the possible adjustment to the revenue requirement described below.

In calculating the jurisdictional revenue requirement in this proceeding, Duke Energy Indiana did not adjust the federal income tax rate to reflect a tax deduction under the Jobs Creation Act because it does not expect to be allowed to take the deduction in 2012 due to its expected tax position after reflecting bonus depreciation for the Edwardsport IGCC plant. Petitioner indicated in its July 24, 2012 Docket Entry response that it would notify the Commission in a future ECR proceeding when it had made a definite determination on the in-service date, for tax purposes, of the Edwardsport IGCC plant. When questioned further at the evidentiary hearing, Ms. Douglas indicated that if the Company knew that bonus depreciation would not be reflected in 2012, the revenue conversion factor used in this proceeding would be different and the proposed Rider 62 revenue requirements would have been lower. Ms. Douglas also indicated that if bonus depreciation is not ultimately reflected in 2012, then Petitioner would further evaluate whether an adjustment should be made. Therefore, the Commission finds that if no bonus depreciation related to the Edwardsport IGCC plant is reflected in 2012 and Petitioner is ultimately able to take advantage of the Jobs Creation Act deduction, Petitioner shall make an adjustment (in the first ECR proceeding following this determination) reflecting the revenue requirement impact that such knowledge would have had on the revenue requirement being approved herein for Rider 62. If bonus depreciation related to the Edwardsport IGCC plant is reflected in 2012, Petitioner shall notify the Commission in the pending, or subsequent if none are pending, ECR and IGCC proceeding.

Petitioner should be authorized to recover its O&M and depreciation expenses related to its NO_x Compliance Plan, Phase 1 CAIR/CAMR Compliance Plan, Gallagher DSI Projects and environmental capital maintenance projects, in accordance with Rider 71, as described in the testimony and exhibits of Ms. Douglas, including the reconciliation of such expenses for the period July 2011 through December 2011 (and also for January 2011 through June 2011, in the case of Gallagher DSI System expenses) and the estimated amounts for the period January 2012 through June 2012.

Petitioner should also be authorized to recover its SO_2 and NO_x emission allowance costs in accordance with Rider 63, as described in the direct testimony and exhibits of Ms. Douglas, including the reconciliation of such expenses for the period September 2011 through February 29, 2012 and the estimated amounts for the period September 2012 through February 2013.

In addition, Petitioner's ongoing review progress report related to its NO_x Compliance Plan, Phase 1 CAIR/CAMR Compliance Plan, and 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.

9. <u>Confidential Information</u>. Petitioner filed a Motion for Protection of Confidential and Proprietary Information ("Motion") with the Affidavits of Mr. Joseph A. Miller, Jr. and Mr. John P. Griffith on May 23, 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, and specific emission allowance transaction prices. In a June 1, 2012 Docket Entry, such information was found to be entitled to confidential protection on a preliminary basis.[10] On June 6, 2012, Petitioner filed a second Motion for Protection of Confidential and Proprietary Information with the Affidavits of Ms. Diana L. Douglas and Mr. Joseph A. Miller, Jr. In this Motion, Petitioner demonstrated a need for confidential treatment for certain load and price information concerning a confidential Commission-approved special contract with Nucor and certain retirement detail that contains actual costs. In a June 14, 2012 Docket Entry, such information was found to be entitled to confidential protection on a preliminary basis.

The Affidavits of Mr. Miller, Ms. Douglas and Mr. Griffith 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.

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[10] In the June 1, 2012 Docket Entry, it was noted that the Nucor Interruptible Service and Retirement Detail information did not fall within the type of information described in the Motion and Petitioner's supporting affidavits. Petitioner was instructed to submit an additional motion and supporting affidavit.

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 December 31, 2011, is hereby approved, subject to further adjustment as set forth in Finding No. 8. 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 the first billing cycle of September 2012 or for all bills rendered after the effective date of the Commission's Order in this proceeding, if later, upon the filing of the final Rider with the Commission's Electricity Division.

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

6. The detailed cost estimate information, Nucor interruptible service detail, and retirement detail contained in the testimony and exhibits admitted in this Cause are found to be confidential and trade secrets and therefore excepted from public access.

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

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

APPROVED: AUG 29 2012

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

Brenda A. Howe

Brenda A. Howe
Secretary to the Commission