ORIGINAL

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF DUKE ENERGY INDIANA, INC. SEEKING AUTHORITY TO REFLECT ADDITIONAL VALUES OF QUALIFIED POLLUTION CONTROL PROPERTY UNDER CONSTRUCTION IN ITS RATES THROUGH ITS STANDARD CONTRACT RIDER NO. 62, PURSUANT TO IND. CODE SECTIONS 8-1-2-6.6, 8-1-2-6.8 AND 170 I.A.C. 4-6-18; SEEKING APPROVAL OF AN ONGOING REVIEW PROGRESS REPORT CONCERNING CERTAIN CLEAN COAL TECHNOLOGY PROJECTS PURSUANT TO IND. CODE SECTION 8-1-8.7-7; SEEKING APPROVAL OF AN UPDATED COMPLIANCE PLAN, UPDATED COST ESTIMATES AND ESTIMATED IN-SERVICE DATES FOR ENVIRONMENTAL PROJECTS; SEEKING APPROVAL OF AN ADJUSTMENT TO ITS RATES THROUGH ITS CLEAN COAL OPERATING COST REVENUE ADJUSTMENT STANDARD CONTRACT RIDER NO. 71, IN ACCORDANCE WITH IND. CODE SECTION 8-1-8.8-11; AND SEEKING APPROVAL OF AN ADJUSTMENT TO ITS RATES THROUGH ITS SO2, NOX AND HG EMISSION ALLOWANCE ADJUSTMENT, STANDARD CONTRACT RIDER NO. 63	CAUSE NO. 42061 ECR 21 APPROVED: AUG 14 2013

ORDER OF THE COMMISSION

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

On April 29, 2013, Duke Energy Indiana, Inc. ("Petitioner," "Company" or "Duke Energy Indiana") filed a Petition with the Indiana Utility Regulatory Commission ("Commission") seeking: (1) to reflect additional values of qualified pollution control property ("QPCP") in its rates and charges for electric service, through Standard Contract Rider No. 62 ("Rider 62"); (2) approval of an ongoing review progress report 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 July 18, 2013 at 1:30 p.m. in Room 224, PNC Center, 101 West Washington Street, Indianapolis, Indiana. Petitioner and the Indiana Office of Utility Consumer Counselor ("OUCC") appeared at the hearing. Petitioner offered into evidence the testimony and exhibits of Mr. Joseph A. Miller, Jr., Ms. Diana L. Douglas, Mr. Joseph F. McCallister, and Mr. Charles E. Howell. The OUCC presented the testimony of Mr. Wes R. Blakley and Ms. Cynthia Armstrong. The evidence of both parties was admitted without objection. 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 as defined by Ind. Code § 8-1-2-1 and requests relief pursuant to Ind. Code §§ 8-1-2-6.6, 8-1-2-6.8, 8-1-2-42(a), Ind. Code chs. 8-1-8.7 and -8.8, and 170 IAC 4-6. The Commission has jurisdiction over Petitioner and the subject matter of this proceeding.

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

3. **Petitioner's Electric Generating Properties.** Petitioner's electric generating properties consist of: (1) four primarily coal-fired electric generating stations (Cayuga, Gallagher, Gibson, and Wabash River) having a total of fourteen coal-fired generating units; (2) one hydroelectric generation station; (3) the Noblesville Repowering Project; and (4) 38[1] rapid-start peaking units.[2]

4. **Background to this Proceeding.**

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

On July 3, 2002, this Commission issued an order in consolidated Cause Nos. 41744-S1 and 42061, wherein, among other things, we: (1) found that Petitioner's NOx Compliance Plan was reasonable; (2) issued a Certificate of Public Convenience and Necessity ("CPCN") for the use of clean coal technology; (3) approved the use of Petitioner's proposed QPCP; (4) approved

[1] It appears that Mr. Miller's direct testimony contained a typographical error as the correct number of units is 38 rather than 37.

[2] Duke Energy Indiana's filing also indicated that it anticipates having approximately 586 MW of capacity this summer from the Edwardsport IGCC plant.

Petitioner's updated cost estimates related to its NOx Compliance Plan equipment; and (5) approved Rider No. 62 that allows for construction work in progress ("CWIP") ratemaking treatment for Petitioner's QPCP. We found that Petitioner may update the value of its QPCP for CWIP ratemaking purposes no more often than every six months. Additionally, we found that, under our ongoing review rules, Petitioner should submit, at least annually, a progress report detailing any revisions in its cost estimates or in the planned construction of its clean coal technology projects.

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

The final CAIR requires major SO_2 and NOx emission reductions, established annual and seasonal NOx trading programs, and set limitations on use of SO_2 emission allowances. The Indiana Air Pollution Control Board adopted the final CAIR on November 1, 2006.[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 ("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

[3] 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. On March 29, 2013, the Solicitor General, on behalf of EPA petitioned for a writ of certiorari with the U.S. Supreme Court to review the D.C. Circuit Court's August 21, 2012 decision regarding CSAPR.

[4] 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.

projects as provided in the Settlement Agreement; and (8) approved the timely recovery of costs associated with Petitioner's CAIR/CAMR Compliance Plan.

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

The MATS rule regulates hazardous air pollutant emissions from new and existing coal- and oil-fired steam electric generating units that are greater than 25 MWs in capacity. Specifically, it is a command and control program that imposes unit-by-unit restrictions on mercury, acid gases such as hydrogen chloride, and certain non-mercury metals such as arsenic, chromium, nickel and selenium. The MATS rule also requires sources to follow certain work practice standards designed to minimize emissions of organic materials and to minimize hazardous air pollutant emissions during periods of start-up and shutdown. The deadline for compliance is April 16, 2015.

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

On April 3, 2013, in Cause No. 44217, the Commission approved Petitioner's Phase 2 MATS Compliance Projects as QPCP eligible for CWIP ratemaking treatment in accordance with Ind. Code §§ 8-1-2-6.6 and -6.8, and as clean energy projects qualifying for incentives in accordance with Ind. Code § 8-1-8.8-11.

d. **Dry Sorbent Injection Projects at Gallagher Units 2 and 4**. As part of the terms of a Consent Decree agreed to by Petitioner and the U.S. Department of Justice, 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.

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

5. **Relief Sought in this Proceeding.** In this six-month update proceeding, Petitioner requests the authority to reflect additional values of QPCP, as of December 31, 2012, in its rates and charges for electric service via Rider 62. Petitioner further requests approval of: (1) an ongoing review progress report concerning certain clean coal technology projects; (2) updated environmental projects, cost estimates and estimated in-service dates for environmental projects; (3) an update and adjustment to Petitioner's Clean Coal Operating Cost Revenue Adjustment Rider 71, (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 63.

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

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

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

a. **Compliance Plan 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 Phase 1 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 20 ("ECR 20"), the most recent six-month update case.

Additionally, Mr. Miller stated that the estimated costs of the NOx Compliance Plan have changed, but that the Company's cost estimates have been reasonably accurate. He explained that as with any multi-year plan there are ongoing impacts and refinements that could potentially affect costs. He indicated that changes in cost estimates generally reflect adjustments on the catalyst bed replacements planned for future years. He further added that with the Commission's approval, for CWIP ratemaking purposes, Petitioner proposes to include the actual costs of the projects once they are known, whether higher or lower than the original estimates. Mr. Miller then testified that the NOx Compliance Plan cost estimates that were previously approved have increased due to an additional selective catalytic reduction ("SCR") catalyst replacement anticipated in 2022. He stated that in the Company's last ECR filing, only a partial year of actual costs for 2012 was included and that this filing includes the actual costs through year-end 2012 and a forecast period of 2013-2022. Overall, Petitioner's estimated costs for its NOx Compliance Plan reflect an increase in the cost estimate by $3.8 million. Mr. Miller also mentioned the fact that although several of the NOx projects are in-service,[5] that does not mean that additional construction dollars will not be spent or recorded on the project.

Mr. Miller testified that the only projects added to the Company's Phase 1 CAIR/CAMR Compliance Plan since the Settlement Agreement in Cause Nos. 42622/42718 have been the mercury emission monitors that were under construction or purchased by the time CAMR was vacated. Mr. Miller testified that the mercury monitors at Gibson Station were either installed or almost completely installed at that time. The Company completed the installation of the Gibson Station monitors and one monitor at Gallagher Station, and placed the remainder of the purchased monitors in storage. Mr. Miller testified that in anticipation of pending MATS 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 the equipment operates and to collect more

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

data about the Company's actual mercury emissions from these units to help with compliance planning.

Mr. Miller provided an update on the status of the mercury monitors at Wabash River Station that were approved as part of the Company's Phase 1 CAIR/CAMR Compliance Plan filing. He testified that in light of the Company's plan to retire Wabash River Units 2-5 and either retire or convert Unit 6 to operating on natural gas in accordance with the MATS rule, as well as the previous sale of Wabash River Unit 1 to Wabash Valley Power Association ("WVPA"), the Company believes it will not need to install these monitors at Wabash River Station. Accordingly, Duke Energy Indiana has changed the status of these mercury monitors from "deferred" to "cancelled" in Petitioner's Exhibit A-2.

Mr. Miller described the emissions benefits associated with the Gallagher baghouses. He explained that the baghouses resulted in significant decreases in emission rates of filterable particulate matter ("PM"), mercury, and SO_2.

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

Mr. Miller indicated that Petitioner proposed, for CWIP ratemaking purposes, to include only the actual costs of the projects once they become known, whether those costs are higher or lower than the original estimate on any specific project. He stated he believes the current cost estimates of Petitioner's Phase 1 CAIR/CAMR Compliance Plan continue to be reasonable.

Mr. Miller discussed the status of Petitioner's Gallagher DSI Projects that were part of the Consent Decree reached with the U.S. Department of Justice. 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 2013 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 2012 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. He testified that the cost estimate for the required equipment remained reasonable.

Next, Mr. Miller discussed the reasons why Petitioner is constructing Phase 2 MATS Compliance Projects. He explained that the Company must further reduce the mercury emissions from its generating facilities in order to comply with the MATS rule and its anticipated compliance date of April 16, 2015. He continued that the primary focus of the plan is reducing the mercury emissions at Cayuga and Gibson stations.

Mr. Miller described the Company's current Phase 2 MATS Compliance Plan, which has not changed since its approval in Cause No. 44217. Mr. Miller testified that the estimated costs of the Phase 2 MATS Compliance Plan have not changed either and that the Company believes that the Phase 2 Compliance Projects will be completed on time and within the approved cost estimate. However, as with any multi-year plan, he would expect to see minor changes from ongoing impacts and refinements to the projects as a normal part of ongoing construction program.

Mr. Miller noted that since the approval of the Phase 2 MATS Compliance Plan, the General Works Contract for the Cayuga SCR construction was signed, the majority of the foundation work had been completed, and the SCR ductwork and structural steel fabrication had begun. He explained that 21 of 22 major contracts for the Cayuga SCR projects and 3 of 6 major contracts for the Cayuga sorbent projects have been signed, with approximately $124 million in contracts going to Indiana-based contractors, and that site mobilization is expected to begin in May 2013. He stated that no construction activities were underway yet at Gibson Station.

Mr. Miller discussed the Phase 2 MATS Compliance Plan development costs included in this proceeding. He stated that in Cause No. 44217, these costs were estimated at $17.242 million, but that the final development costs total $15.836 million on a total company basis.

b. **Rider 62**. Ms. Diana L. Douglas described the proposed implementation of CWIP ratemaking treatment via Rider 62, and provided the schedules and information required by 170 IAC 4-6-12. Specifically, Ms. Douglas provided information establishing the incremental value of QPCP investment through December 31, 2012 for approved NOx and Phase 1 CAIR/CAMR Compliance Plan projects and of related capital maintenance projects, as well as for the Gallagher DSI System for which Petitioner is seeking recovery; showed the computation of the jurisdictional revenue requirement associated with that investment; and determined the allocation of the jurisdictional revenue requirement to various retail customer groups. Ms. Douglas explained that consistent with the Commission's Order in consolidated Cause Nos. 41744-S1 and 42061 and subsequent related Orders, the QPCP projects will be deemed to be under construction, and Petitioner will continue to receive revenues through Rider 62, until the Commission determines that these projects are used and useful in a proceeding that involves the establishment or investigation of Petitioner's base rates and charges, or until these projects no longer satisfy the other requirements of the Commission's CWIP ratemaking rules.

Ms. Douglas testified regarding 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"). In addition, she explained that depreciation of an asset on the accounting books stops upon retirement. The Company has appropriately reflected this in the actual and estimated depreciation amounts included in this filing, as appropriate based on the dates the equipment was retired.

Ms. Douglas explained that because Petitioner has determined that additional cost to complete the mercury monitors at Wabash River Station will not be incurred given the Phase 2 MATS Compliance Plan and that the project will not be put into service, the costs have been removed from the investment balance, so it will no longer earn a return. Instead, Petitioner included for amortization and recovery in Rider 71 the costs incurred with the Phase 2 MATS Compliance Plan development.

Ms. Douglas 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.

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

Mr. Charles E. Howell, discussed the capital maintenance projects for which costs, incurred after June 30, 2011, have been included. Mr. Howell explained the following eighteen capital maintenance projects, of which ten were in service and eight 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[6]	In Service
Gallagher 2 Baghouse Bag Replacement	Baghouse	In Service
Gibson 1-5 Soda Ash Pumps	SCR	In Progress
Soda Ash Tank Platform/Vent/Insulation	SCR	In Service
Gibson 3 SCR SBS probes	SCR	In Service
Gibson 1-3 FGD Service Water Strainer	FGD	In Service
Gibson 1 SCR NOx Monitor Control System	SCR	In Service
Gibson 5 SCR NOx Monitor Control System	SCR	In Service
Gibson 1 B2 SCR Dilution Air Fan Motor	SCR	In Progress
Gibson 1-5 Ammonia Delivery System	SCR	In Progress
Gibson 1-5 Reagent Air Receiver Tank	FGD	In Service
Cayuga 2 FGD EJ6 and EJ7 Replacement	FGD	In Service
Gibson 2 SCR Turning Vanes	SCR	In Progress
Gibson 1-5 Absorber Recirculating Pump Motor Rewind	FGD	In Progress
Gibson 1-3 Reactive Prep Sump Pump	FGD	In Progress
Gibson 3 Ball Mill Liner	FGD	In Progress
Gibson 2 Ball Mill Liner	FGD	In Progress
Gibson 1-3 FGD Oxidation Air Humidity Water Source	FGD	In Service

[6] Flue Gas Desulfurization

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

Ms. Douglas explained the inclusion of costs associated with the Gallagher DSI Projects, and the Phase 2 MATS Compliance Projects which are being included for the first time in this filing, and that were discussed further by Mr. Miller.

Ms. Douglas described the changes in her Exhibit B-2, pages 6 and 7, from what was filed in ECR 20. She stated that in order to streamline the reflection of accumulated depreciation resulting from retirements of plant at the individual project level, the Company is showing depreciation on a gross basis in its exhibits. She noted that this format change has no impact on the bottom line and that the Company has continued to remove depreciation associated with retired plant, but that it has been removed as a lump sum for all retired plant rather than showing removals from each individual project from which something was retired. She also explained that other format changes on pages 6 through 9 were made to show depreciation as one amount rather than showing separate monthly amounts, since the monthly amounts are provided in the Rider 71 portion of the filing.

Ms. Douglas explained that there was an additional adjustment to the beginning balance of accumulated depreciation for a capital maintenance project at Gibson Station that was inadvertently omitted from previous filings and is already in-service.

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

Ms. Douglas also explained that Petitioner pledged to return the difference between the property tax expense approved in Cause No. 42359 and actual jurisdictional property tax expense, if lower. Ms. Douglas testified that based on this commitment there is currently estimated a $154,000 over-refund amount in ECR 21 rates and that the Company proposes for administrative convenience that the final reconciliation for tax years 2010-pay-2011 and 2011-pay-2012 expense be made in Rider 71 in the ECR 22 filing, once final collection amounts are known from ECR 20 billings. Therefore, no credit or charge has been included in the development of either Rider 62 or 71 in this filing. She stated that the Company will continue to report the estimated and final amounts in a Rider 62 exhibit until the 2012-pay-2013 tax year amounts are final and that if the final amounts are ultimately less than the amount in base rates, the Company will refund the appropriate amount to customers in a future ECR filing.

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 WVPA.

c. Rider 71. Ms. Douglas also explained and provided support for 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, 2012, and the estimated costs for the period January through June 2013. Ms. Douglas also testified that the Company is including for the first time in this filing, the amortization of Phase 2 MATS Compliance Plan development costs, including preliminary costs incurred for mercury monitors at Wabash River Station, over a three-year period, which costs were approved for recovery in Cause Nos. 42622/42718 and reaffirmed in Cause No. 44217. Ms. Douglas continued by stating that the Company was including a credit to customers in the amount of incremental demand revenues under a contract with Nucor Corporation (the "Nucor Credit"). Ms. Douglas explained the inclusion of a similar credit under a contract with Temple-Inland (the "Temple-Inland Credit"). Ms. Douglas further explained the proposed revenue requirement recovery amount resulting from the estimated jurisdictional O&M and depreciation expenses expected to be incurred for the six months ended June 30, 2013, the revenue requirement resulting from estimated jurisdictional depreciation expenses, amortization of the retail jurisdictional portion of Phase 2 MATS Compliance Plan development costs, and the reconciliation amount for the six months ended December 31, 2012.

Mr. Howell testified that the projects having incremental O&M expenses associated with the Company's NOx Compliance Plan are the Gibson Station Units 1-5 SCRs, Gibson Station Units 1-5 arsenic mitigation system, and the Gibson Station Units 1-5 sulfur trioxide mitigation systems. He stated that these incremental costs will fluctuate based on demand and the generation level of the units. Mr. Howell also testified regarding the incremental O&M expenses associated with the Company's Phase 1 CAIR/CAMR Compliance Plan. He explained that the projects associated with these expenses are the Cayuga Units 1 and 2 FGDs, Gibson Station Units 1-3 FGDs, Gibson Station Units 4 and 5 FGD upgrades, and Gallagher Units 1-4 baghouses. He concluded that the incremental costs associated with these projects will also vary based on demand and the generation level of the units. Finally, Mr. Howell explained the incremental O&M expenses associated with the Gallagher DSI Project. 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.

Ms. Douglas explained that pursuant to the Consent Decree entered into by the Company and the U.S. Department of Justice resolving New Source Review litigation, the Company retired Gallagher Units 1 and 3 at the end of January 2012. She explained that the Commission's December 28, 2011 Order in Cause No. 43956 approves the amortization and recovery of the net book value of these units over 14 years, and as such the estimated depreciation expense for the Gallagher Units 1 and 3 projects which are included in Riders 62 and 71 has been reflected using a 14-year amortization rather than using the approved accelerated depreciation rates which had been previously used for the NOx Compliance Plan 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. She stated that the Order in Cause No. 43114 IGCC 4S1 also approved a provision of the 2012 Settlement Agreement which allowed the Company to continue to use the accelerated rates previously approved by the Commission for use of NO_x and Phase 1 CAIR/CAMR projects for purposes of Riders 62 and 71 recovery, while also approving the use of non-accelerated depreciation rates for book accounting purposes until the next base rate case.

Ms. Douglas testified that depreciation has been adjusted, as appropriate, for retirements, similar to Rider 62, showing the depreciation amounts for projects on a gross basis, which has the effect of removing depreciation for retired plant and results in the same depreciation amount as would have been reflected if the Company had continued its net presentation.

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 July through December 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 Orders in Cause No. 43754 and Cause No. 42061 ECR 15 ("ECR 15") using the revenue requirements proposed in this 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 9, which was approved by the Commission on April 3, 2013). 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 July through December 2012 using 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.

d. **<u>Rider 63</u>.** Finally, Ms. Douglas explained and provided support for 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 February 28, 2013, and the estimated NOx and SO_2 EA costs for the period September 2013 through February 2014.

Ms. Douglas testified that a proposed factor of $0.000189 per kWh is being requested for the September 2013 through February 2014 billing period. She testified this factor included realized gains and losses from the sale of SO_2 and annual NOx emission allowances. She further testified that no estimates of EA sales during the projected period were included.

Ms. Douglas stated that 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 decrease by $0.09 or 0.1%, when compared to the last approved factor. She explained that when compared to the factor in place for September 2012 through February 2013, this typical residential customer will see an increase of $0.08 or 0.1%.

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

Mr. Joseph F. McCallister explained the continued uncertainty regarding the timing of potential implementation of CSAPR and stated it is currently anticipated that CAIR will be in effect for EA compliance for 2013. He explained the impact of the vacature and current status of CSAPR on the CAIR programs, CAIR allowances in inventory and compliance. He stated that in October 2012, EPA returned the vintage 2013 CAIR Annual and Seasonal NOx allowances because CAIR is anticipated to remain in place with the 2013 seasonal and annual NOx requirements. In addition, EPA allocated 2014 Annual and Seasonal NOx allowances. Mr. McCallister further explained that while CAIR is in effect, SO_2 compliance will take place under the CAIR rules using the compliance ratio[8] mandated by CAIR and that the ratio is increasing.

Mr. McCallister summarized that given the status of CSAPR and assuming CAIR is in place for the 2013 compliance period, the Company will have to comply with the CAIR Annual NOx, CAIR Seasonal NOx, and Title IV/Acid Rain SO_2 requirements 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. Based on recent market activity, 2013 CAIR SO_2 EAs are trading at approximately \$0.65/EA, 2013 CAIR Annual NO_x EAs are trading at approximately \$40/EA, and 2013 CAIR Seasonal NO_x EAs are priced at approximately \$17.50/EA.

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

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

Mr. McCallister explained that Petitioner's goal is to approach a balanced position after considering allocations provided by EPA, existing inventory and emission usage based on

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

forecasting and actual usage. In addition, because EAs that do not have to be surrendered to the EPA are valid in later years, Petitioner must also consider the Company's position in later years.

Mr. McCallister described the Company's current positions concerning CAIR SO_2, Seasonal and Annual NOx EAs, stating that they are longer than would be required for compliance through the 2015 compliance period and that the uncertainty relating to the future for EAs remains and has led to low EA prices. Mr. McCallister testified that there continues to be uncertainty about the Company's EA positions given the effects of future power, coal and gas pricing on the Company's generation fleet, along with the legal uncertainty surrounding CAIR and CSAPR. Mr. McCallister further explained that the Company continues to assess the EA market and monitor the developments of CAIR and CSAPR. He said Petitioner looks for ways to optimize the EA positions by using the EA market to buy and sell EAs, as needed, passing through to customers the costs of purchases and the gains or losses on sales in the normal course of business. Mr. McCallister stated that the Company purchases and sells EAs in an open and active market to provide energy to native load customers as economically as possible.

Mr. McCallister testified that there were EA transactions during 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 that these forecasts are based on the same modeling that the Company has used for a number of years.

8. <u>Summary of the OUCC's Evidence</u>. Mr. Wes R. Blakley, Senior Utility Analyst for the OUCC, testified that he had reviewed Petitioner's filings in this Cause and the Commission's Order in ECR 20 and nothing came to his attention that would indicate Petitioner's calculation of estimated ECR adjustment factors for the relevant period is unreasonable. Mr. Blakley noted that Petitioner has fully amortized the Wheatland Plant's deferred asset balance and that the revenues from the Wabash River Unit 1 can be refunded to customers. He also noted that the Company has requested recovery of costs associated with the Gallagher DSI Projects, approved December 28, 2011 in Cause No. 43956, and a recalculation of depreciation expense related to the pollution control assets at retired Gallagher Units 1 and 3. Mr. Blakley described Petitioner's proposed apportionment of the revenue from the Nucor demand charge to the impacted riders and noted that the total amount is reflected in Rider 71 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 referenced that the testimony of Ms. Douglas and Mr. Howell discussed capital maintenance projects undertaken by Petitioner. Mr. Blakley noted that the Company had filed corrective testimony that increased the amount of deferred income taxes in the capital structure, which in turn lowered the weighted average rate of return and as a result lowered the revenue requirement.

Mr. Blakley noted that for Rider 62, the monthly bill of a typical residential customer using 1,000 kilowatt-hours would decrease by eleven cents, or 0.14% when compared to the last approved factor (excluding other various tracking mechanisms). And with regard to Rider 71, the monthly bill of a typical residential customer using 1,000 kilowatt-hours would decrease[9] by approximately thirteen cents, or approximately 0.2% when compared to the last approved factor (excluding other various tracking mechanisms).

Ms. Cynthia M. Armstrong, Senior Utility Analyst in the Electric Division for the OUCC, testified that she had reviewed Petitioner's filings and discovery in this Cause as well as participated in a teleconference with the Company regarding emission allowance sales during this ECR recovery period. Ms. Armstrong testified that Petitioner had three SO_2 EA sales during this period that were less than the weighted average inventory cost, which ultimately resulted in the Company incurring a loss on the sale. She stated that since ratepayers receive 100% of the gains and losses on the Company's allowance sales, this loss was included in calculating the proposed EA adjustment factor for this proceeding. She noted that Duke Energy Indiana provided an explanation for carrying out the sale, but indicated the OUCC still had concerns with the sale.

She explained that the OUCC was not aware of any Acid Rain or CAIR allowance trading programs that penalize participants for holding more allowances than what their compliance obligations require. Ms. Armstrong noted that the OUCC understands the Company's position that it is better to obtain some value from the excess allowances than nothing at all, but the OUCC still questions whether selling the allowances is in the best interest of ratepayers. Ms. Armstrong testified that the OUCC is not challenging the inclusion of the losses from the SO_2 sales in this proceeding, but wanted the Commission to be aware of its concerns regarding the Company's EA sales during this period. She explained that the OUCC plans to discuss the issue further with the Company to try and reach an agreement on the treatment of EA sales losses and guidelines on the sale of EAs when the market price is below inventory cost.

9. **Summary of Petitioner's Rebuttal.** Mr. McCallister provided rebuttal testimony in response to Ms. Armstrong's testimony on the sale of SO_2 EAs. However, he noted that the Company is not filing rebuttal testimony to find fault with Ms. Armstrong's testimony, but to add another perspective on the SO_2 EA sales. He explained that Petitioner appreciates the opportunity to work with the OUCC going forward on EA inventory management strategy and that the Company has agreed not to sell any additional SO_2 EAs going forward until the meeting with the OUCC occurs.

Mr. McCallister explained that while the Company is allowed to bank SO_2 EAs under existing programs, customers have benefited through the sale of EAs over time and that market activity in previous periods has resulted in cumulative gains on SO_2 and NOx EA sales and auctions that have been credited to customers since March 2006 when the Company began optimizing its allowance inventory using market sales. He also noted that in this ECR filing, a sale of NOx allowances resulted in a gain.

Mr. McCallister continued by stating that the market for SO_2 EAs can be characterized by low prices, limited activity and on-going regulatory uncertainty and that the future outlook does

[9] Although Mr. Blakley's testimony indicated the monthly bill would increase, this appears to be a typographical error.

not appear to show a significant increase in value. Mr. McCallister testified that the Company last purchased SO_2 EAs in the spring of 2009, when its forecast showed Petitioner was short. He explained that when CSAPR was finalized in July 2011, the value of SO_2 EAs had already declined significantly and that market prices have been very low for the past few years. Mr. McCallister explained that although the Company hasn't purchased any new SO_2 EAs for years, the inventory continues to grow due to SO_2 allocations received from the EPA along with the decline of the Company's compliance needs. He explained that Petitioner's forecast shows it being long in inventory for the foreseeable future and that although current market prices are less than the current average cost of inventory, which leads to an appearance of the sale being a loss,[10] the majority of inventory is made up of zero cost program allowances that were allocated by EPA. By selling these SO_2 EAs, the Company believes obtaining some value for these SO_2 EAs now benefits customers. By holding onto the excess allowances, the Company runs the risk that the market will remain low or decline further and could lose the opportunity to obtain this value for customers.

10. Commission Discussion and Findings. Based upon the evidence presented, the Commission finds that Petitioner's request should be approved. Specifically, the Commission finds that Petitioner should be authorized to reflect the additional values through December 31, 2012 of the NOx Compliance Plan, Phase 1 CAIR/CAMR Compliance Plan, Gallagher DSI Projects, capital maintenance, and Phase 2 MATS Compliance Projects in its rates and charges for electric service in accordance with Duke Energy Indiana's Rider 62, as indicated in the direct testimony and exhibits of Ms. Diana L. Douglas and subsequently corrected as noted by the OUCC.

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 July 2012 through December 2012 and the estimated amounts for the period January through June 2013.

Petitioner should also be authorized to recover its SO_2 and NOx EA costs in accordance with Duke Energy Indiana's Rider 63, as described in the direct testimony and exhibits of Ms. Douglas, including the reconciliation of such expenses for the period September 2012 through February 2013 and the estimated amounts for the period September 2013 through February 2014.

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 a decrease of \$0.33 or 0.4% when compared to the last approved factors.

In addition, Petitioner's ongoing review progress reports related to its NOx Compliance Plan, Phase 1 CAIR/CAMR Compliance Plan, Gallagher DSI Projects, and Phase 2 MATS Compliance Projects are hereby approved. We find that the updated plans, construction cost estimates and in-service dates provided by Petitioner in this Cause are reasonable and are hereby

[10] Duke Energy Indiana is required by FERC to use the weighted average cost of inventory method for valuing gains and losses for accounting purposes.

approved as such. Further, we find that Petitioner's NOx Compliance Plan CPCN should be modified to incorporate the changes in its components and cost estimates as set forth herein.

11. **Confidential Information.** Petitioner filed a Motion for Protection of Confidential and Proprietary Information ("Motion") with the Affidavits of Mr. Joseph A. Miller, Jr., Mr. Joseph F. McCallister, and Ms. Diana L. Douglas on May 22, 2013. In this Motion, Petitioner demonstrated a need for confidential treatment for the detailed cost estimates and actual expenditures associated with Petitioner's environmental compliance plan, unit-specific O&M costs, specific EA transaction prices, certain load and price information concerning confidential Commission approved special contracts, and certain retirement detail that contains actual costs. In a June 3, 2013 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 identified confidential information contains "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, including QPCP values as of December 31, is hereby approved. The Rider 62 shall go into effect upon the filing of the final Rider with the Commission's Electricity Division for all bills rendered after the effective date of this Order.

2. Petitioner's proposed updated Rider 71, including reconciliation through December 31, 2012 and estimated amounts for January 1, 2013 through June 30, 2013, is hereby approved. The Rider 71 shall go into effect upon the filing of the final Rider with the Commission's Electricity Division for all bills rendered after the effective date of the Commission's Order in this proceeding.

3. Petitioner's proposed updated Rider 63, including reconciliation through February 2013 and estimated emission allowance costs for September 2013 through February 2014, 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 September 2013 or for bills rendered after the effective date of this Order, if later.

4. Petitioner's ongoing review progress reports related to its NOx Compliance Plan, Phase 1 CAIR/CAMR Compliance Plan, Gallagher DSI Project, and Phase 2 MATS Compliance Projects are hereby approved. Petitioner's NOx Compliance Plan CPCN is modified to incorporate the changes in its components and cost estimates as set forth herein.

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

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

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

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

APPROVED:

AUG 14 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