ORIGINAL

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF DUKE ENERGY INDIANA, INC., FOR APPROVAL OF (1) A PHASE 3 PLAN TO ENSURE COMPLIANCE WITH REGULATED AIR EMISSION LIMITS; (2) PETITIONER'S PHASE 3 PLAN PROJECTS AS QUALIFIED POLLUTION CONTROL PROPERTY AND CLEAN ENERGY PROJECTS; (3) CERTAIN FINANCIAL INCENTIVES IN CONNECTION WITH PETITIONER'S PHASE 3 COMPLIANCE PLAN, INCLUDING THE TIMELY RECOVERY OF COSTS INCURRED DURING CONSTRUCTION AND OPERATION OF THE CLEAN ENERGY PROJECTS VIA DUKE ENERGY INDIANA'S RIDER NOS. 62 AND 71, AND THE USE OF ACCELERATED DEPRECIATION; (4) THE AUTHORITY TO DEFER POST-IN-SERVICE CARRYING COSTS AS A REGULATORY ASSET UNTIL THE APPLICABLE COSTS ARE REFLECTED IN PETITIONER'S RATES; (5) THE AUTHORITY TO DEFER DEPRECIATION AND INCREMENTAL OPERATION AND MAINTENANCE EXPENSES ON AN INTERIM BASIS UNTIL THE APPLICABLE COSTS ARE REFLECTED IN PETITIONER'S RATES; AND (6) THE TIMELY RECOVERY OF FUTURE COMPLIANCE PLAN DEVELOPMENT, ENGINEERING, TESTING AND PRE-CONSTRUCTION COSTS	)	**CAUSE NO. 44418** **APPROVED:** AUG 27 2014

ORDER OF THE COMMISSION:

Presiding Officers:
David E. Ziegner, Commissioner
Jeffery A. Earl, Administrative Law Judge

On November 7, 2013, Duke Energy Indiana, Inc. ("Duke") filed its Verified Petition in this Cause. On November 12, 2013, Duke filed the direct testimony and exhibits of the following:

- Douglas F. Esamann, President of Duke Energy Indiana;
- Christa L. Graft, Lead Rates Analyst at Duke Energy Business Services LLC ("DEBS");
- Jose I. Merino, Director of Load and Fundamental Forecasting at DEBS;
- Joseph A. Miller, Jr., General Manager, Strategic Engineering, at DEBS;
- Scott Park, Director, IRP & Analytics-Midwest at Duke Energy Progress, Inc.; and
- Michael W. Stroben, Environmental Policy Analysis and Strategy Director at DEBS.

On December 17, 2013, the Citizens Action Coalition of Indiana, Inc., Sierra Club, and Valley Watch, Inc. (collectively "Joint Intervenors") filed a Joint Petition to Intervene in this proceeding, which the Presiding Officers granted on December 31, 2013. On January 10, 2014, Nucor Steel-Indiana, a division of Nucor Corporation ("Nucor") also filed a Petition to Intervene, which the Presiding Officers granted on January 22, 2014.

On February 14, 2014, the Indiana Office of Utility Consumer Counselor ("OUCC") filed the direct testimony and exhibits of the following:

- Anthony A. Alvarez, Utility Analyst in the OUCC's Resource Planning and Communications Division;
- Cynthia M. Armstrong, Senior Utility Analyst in the OUCC's Electric Division;
- Wes R. Blakley, Senior Utility Analyst in the OUCC's Electric Division;
- Maclean O. Eke, Utility Analyst in the OUCC's Resource Planning and Communications Division; and
- Edward T. Rutter, Utility Analyst in the OUCC's Resource Planning and Communications Division.

On March 18, 2014, Duke and the OUCC filed a Settlement Agreement supported by the testimony and exhibits of Mr. Miller, Ms. Graft, and Mr. Blakley. The Joint Intervenors did not file testimony in this case.

The Commission held an evidentiary hearing at 10:00 a.m. on April 24, 2014, in Hearing Room 222, 101 West Washington Street, Indianapolis, Indiana. Duke, Nucor, Joint Intervenors, and the OUCC appeared by counsel and participated at the hearing. At the evidentiary hearing, Duke and the OUCC offered their evidence, which was admitted into the record in this proceeding. Neither Joint Intervenors nor Nucor offered any prefiled evidence into the evidentiary record. No members of the general public appeared or sought to testify at the hearing.

Based upon the applicable law and the evidence herein, the Commission now finds:

1. **Notice and Jurisdiction.** Notice of the evidentiary hearing in this Cause was given and published as required by law. Duke is a public utility as that term is defined in Ind. Code § 8-1-2-1(a). Under Ind. Code ch. 8-1-8.8, the Commission has jurisdiction to approve clean energy projects and associated cost recovery. Therefore, the Commission has jurisdiction over Duke and the subject matter of this proceeding.

2. **Duke's Characteristics.** Duke is a public utility corporation organized and existing under the laws of the State of Indiana with its principal office in Plainfield, Indiana, and is a second tier wholly-owned subsidiary of Duke Energy Corporation. Duke is engaged in rendering retail 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 service to the public.

3. **Relief Requested in this Cause.** Duke requests approval of its proposed Phase 3 plan, as modified in the Settlement Agreement, for ensuring compliance with regulated air emissions limits. In addition, Duke requests the following:

- Approval of its proposed Phase 3 plan projects as qualified pollution control property and clean energy projects;
- Timely recovery of the financing, construction and operating costs and expenses associated with Duke's Phase 3 Plan via Duke's existing Standard Contract Riders No. 62 and 71;

- Authorization for the use of accelerated depreciation in connection with Duke's Phase 3 environmental compliance projects;
- Authorization to defer post-in-service carrying costs as a regulatory asset until the applicable costs are reflected in Duke's rates;
- Authorization to defer depreciation and incremental operation and maintenance costs on an interim basis until the applicable costs are reflected in Duke's rates;
- Timely recovery of future plan development, preliminary engineering, testing and pre-construction costs via Rider 62 and/or Rider 71; and
- Approval of Duke's proposal for ongoing review of its Phase 3 projects through the existing semi-annual Environmental Compliance Recovery filings.

4. Duke's Proposed Compliance Plan. Duke proposed its Phase 3 environmental compliance plan to address the remaining elements of its Mercury and Air Toxics Standards ("MATS") rule compliance strategy. As a result of the settlement with the OUCC, Duke revised its original Phase 3 Compliance Plan to withdraw its request for permanent mercury sorbent traps at the Edwardsport integrated gasification combined cycle ("IGCC") plant.

Duke's Revised Phase 3 Compliance Plan:

Station	Compliance Plan	Estimated In-Service Date
Gibson Station	Unit 1 – PM CEMS, calcium bromide injection system Unit 2 – PM CEMS, calcium bromide injection system Unit 3 – Precipitator refurbishment, PM CEMS, calcium bromide injection system Unit 4 – Precipitator refurbishment, PM CEMS and associated stack improvements, calcium bromide injection system Unit 5 – Precipitator refurbishment, PM CEMS and associated stack improvements, calcium bromide injection system, FGD relief duct dampers	Nov 2014 Nov 2014 Nov 2014 May 2015 – precip refurb Nov 2014 Nov 2014 – precip refurb Aug 2014 – stack improvements Nov 2014 Aug 2014 – stack improvements Nov 2015 – precip refurb and FGD
Cayuga Station	Units 1 and 2 – PM CEMS, calcium bromide injection system	Sept 2014 – PM CEMS Sept 2015 – calcium bromide

5. Duke's Direct Evidence. Mr. Esamann testified that timely recovery of environmental compliance costs is important from a credit quality perspective because it is crucial to Duke and its customers that it be able to finance these needed capital investments on the best terms possible. Mr. Esamann testified that timely cost recovery is reasonable from a ratemaking policy perspective because these costs have been and will be incurred in order to be able to continue to meet Duke's obligation to provide adequate and reliable electric utility service to retail customers in the State of Indiana. He stated that without the necessary investments to comply with emission reduction requirements, Duke's generating units would be have to be shut down.

Mr. Esamann testified regarding the enhancements in Duke's overall compliance strategy relative to its original Phase 2 Plan proposal. Following the Phase 2 Plan proceeding, where Duke received Commission approval to install activated carbon injection ("ACI") systems at Cayuga and Gibson Unit 5, Duke continued evaluating mercury trim control technologies and conducted additional mercury testing at Gibson and Gallagher Stations. As a result, Duke has gained confidence in a better technology, calcium bromide injection, for meeting its mercury emission trimming needs. This technology is operationally, environmentally, and economically superior to ACI and is approximately one-tenth the cost of ACI (both capital and operations and maintenance costs).

Mr. Esamann stated that as a result of Duke's MATS organics work practice standards testing, Duke has verified that ACI is not required at Gallagher Station for MATS rule mercury compliance. Mr. Esamann testified that customer rates would have been as much as an additional 2.0% to 2.5% higher in 2017 had Duke proceeded with ACI as originally proposed in Phase 2. Overall, the new combined Phase 2 and Phase 3 Plans have a lower total rate impact than the Phase 2 Plan as originally proposed. Mr. Esamann testified that the proposed Phase 3 Plan strategy results in significant savings for customers, while still ensuring Duke's ability to meet environmental compliance requirements.

Mr. Stroben explained the various environmental regulations that are affecting Duke's Phase 3 Plan, in particular the MATS rule. He explained that MATS 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. Because MATS is a command and control program and does not allow emission allowance trading, facilities will be forced to retrofit as required to achieve the standard or shut down to avoid operating out of compliance.

Mr. Stroben testified that Duke'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 gross gigawatt-hour of electricity generated. In addition to limits on mercury, Duke's units will also be subject to limits on the emission of acid gases and certain non-mercury metals. The rule allows sources to demonstrate compliance with acid gas requirements by either monitoring emissions of hydrogen chloride directly, or using sulfur dioxide as a surrogate for units equipped with flue gas desulfurization ("FGD") system. For non-mercury metallic hazardous air pollutant emissions, sources can either measure those metals directly or use filterable Particulate Matter ("PM") as a surrogate. In addition, Duke will also be subject to work practice standards to minimize the emission of organic hazardous air pollutants.

Mr. Stroben testified that the deadline for compliance with the MATS rule is April 16, 2015. The Environmental Protection Agency ("EPA") has indicated that, for units installing controls, sources could potentially apply for an extension of up to one year with the Indiana Department of Environmental Management ("IDEM"). Mr. Stroben testified that Duke has requested and received a one-year extension of time to comply with the mercury emissions limits at Cayuga Station Units 1 and 2 and the acid gas and non-mercury metals emissions limits at Gibson Station Unit 5. Mr. Stroben testified that operating out of compliance would subject that facility and its operator to enforcement actions such as fines and administrative orders. Thus, if Duke's MATS-related projects are not complete, it is possible that Duke would have to shut down any units that fail to meet the MATS-imposed emission limits.

Mr. Stroben testified that emission averaging is an option under the MATS rule for facilities with two or more affected generating units. In that case, the average emissions of the two or more units in an averaging plan must be less than the applicable emissions limit. He stated that for mercury, EPA requires that units complying using an averaging plan for mercury have an average emission rate that is 15% to 20% more stringent than had they complied individually. Mr. Stroben testified that if the actual average emissions for a group of units in an averaging plan are not less than the limit, then all of the units in the plan are deemed out of compliance. He testified that the Phase 3 Plan has been established primarily on a strategy of compliance on an individual unit basis, with the option of using facility-wide averaging if there is a problem complying on a unit-by-unit basis.

Mr. Stroben testified that a number of parties representing industry, government, and environmental organizations have requested judicial review of the MATS rule. A decision is expected in the first half of 2014. However, Mr. Stroben stated that Duke has no choice but to proceed while the litigation progresses. Duke would not be able to meet the standards in the rule by the 2015 or 2016 deadline if it did not proceed with construction at this time.

Mr. Stroben summarized Duke's assumed compliance requirements for the MATS Rules as follows:

- Filterable PM: 0.03 pounds of filterable PM per million BTU ("#/mmBTU") of heat input, as measured by a continuous particulate emission monitor; the compliance demonstration alternative is quarterly stack testing.
- Non-Mercury Metals: Under the option of the MATS rule for complying with the Filterable PM provisions or the non-mercury metals provisions, Duke assumed compliance with the Filterable PM requirements and, hence, did not address the non-mercury metals directly.
- Hydrogen Chloride: 0.002 pounds of hydrogen chloride per million BTU of heat input, as measured by a continuous hydrogen chloride emission monitor; compliance demonstration alternatives include quarterly stack testing, or demonstration through an SO_2 emission rate limit of 0.2 #/mmBTU for units with an FGD.
- Mercury: 1.2 pounds of mercury per trillion BTU ("#/TBTU") of heat input, as measured by a continuous emission monitor ("CEM") or mercury sorbent trap device.
- Work Practice Standards for Organics: Institution of a specific burner inspection and combustion testing and tuning program.
- Other specific rule requirements including Work Practice Standards for startup and shutdown periods, clean startup fuel assessments, and changes to opacity limits without continuous particulate emission monitors did not result in cost or modeling characteristic changes on Duke's units.
- A final MATS compliance date of April 16, 2015, unless an extension is granted.

Mr. Stroben also testified regarding the following potential and proposed EPA rules.

Cross-State Air Pollution Rule ("CSAPR"). Mr. Stroben testified that on August 8, 2011, the EPA published the final CSAPR rule to replace the Clean Air Interstate Rule ("CAIR"). CSAPR, which establishes state-level annual sulfur dioxide ("SO_2") and nitrogen oxide ("NO_x") budgets and ozone-season NO_x budgets, was to take effect on January 1, 2012; however on December 30, 2011, the rule was stayed by the U.S. Court of Appeals for the D.C. Circuit. On August 21, 2012, the D.C. Circuit vacated CSAPR and directed the EPA to continue administering CAIR pending completion of a rulemaking to replace CSAPR. On June 24, 2013, the Supreme Court granted the EPA's petition to review the D.C. Circuit's decision. A decision is expected by mid-2014. While Duke cannot predict the outcome of these proceedings, it is likely that CAIR will continue to be implemented for some period of time. Mr. Stroben testified that if CSAPR were to eventually be implemented, the combination of Phase 1 and Phase 2 Plan investments ensures that Duke's units would comply with CSAPR if it were implemented as it was initially finalized.

Interstate Transport of Emissions. Mr. Stroben testified that while CAIR remains in place, the EPA is working toward issuing a proposed rule related to the interstate transport of ozone across the Eastern U.S. The new rule will be based on the current 77 parts per billion ("ppb") standard rather than the 80 ppb ozone standard under CSAPR. Mr. Stroben stated that this rulemaking would not be in place prior to January 1, 2015, when CAIR Phase 2 is scheduled to go into effect. EPA has not announced any plans to undertake a new rulemaking to address the fine particulate matter ("$PM_{2.5}$") non-attainment.

National Ambient Air Quality Standards ("NAAQS"). Mr. Stroben testified that on June 14, 2012, the EPA proposed to lower the annual $PM_{2.5}$ standard from 15 micrograms per cubic meter ($\mu g/m^3$) to a level within the range of 12 $\mu g/m^3$ to 13 $\mu g/m^3$ and retain the current 24-hour standard at 35 $\mu g/m^3$. EPA is to finalize area designations by December 2014. Mr. Stroben testified that once designations are final, states with non-attainment areas will have 18 months to develop a State Implementation Plan outlining how they will reduce pollution to meet the standard by 2021.

Mr. Stroben testified that the current 8-hour ozone standard is 75ppb. Mr. Stroben testified that the potential for EPA to issue a lower standard, possibly in the 60 to 70 ppb range, is a risk for the next EPA review in 2015. Compliance with the next standard would likely be required in the 2020-2023 timeframe.

Mr. Stroben testified that effective August 23, 2010, the 1-hour SO_2 NAAQS requirement is 75 ppb. On July 25, 2013, EPA designated as nonattainment those areas where the 2009-2011 ambient air quality had been shown by means of monitoring to exceed the level of the standard. The area around Duke's Wabash River Station was designated as a nonattainment area. However, according to Mr. Stroben, Duke does not anticipate any incremental requirement to reduce SO_2 emissions at Wabash River Station as a result of this designation due to the planned retirement of Units 2 through 5 and retirement or conversion to natural gas of Unit 6. For those areas not designated as nonattainment the EPA's updated strategy for completing initial area designations would allow either ambient air quality monitoring or computer-based air quality modeling to determine attainment status, with recommendations submitted to EPA by May 2020 or January 2017, respectively. Mr. Stroben testified that any evaluation by IDEM that results in a final nonattainment designation for an area associated with one of Duke's coal-fired stations would place that facility at risk for additional SO_2 emission reduction requirements. Based on EPA's proposed implementation schedule, however, it will be 3-7 years before the degree of risk is understood, and an additional 3-4 years after that before any action would need to be taken by Duke for potential compliance.

Proposed 316(b) Cooling Water Intake Structures Rule ("316(b)"). Mr. Stroben testified that EPA is currently expected to finalize the 316(b) rule for existing facilities by November 20, 2013. It is expected that it will establish aquatic protection requirements for existing facilities and new on-site facility additions with a design intake flow of two million gallons per day or more from rivers, streams, lakes, reservoirs, estuaries, oceans, or other U.S. waters; that utilize at least 25% of the water withdrawn for cooling purposes; and that are a point source as defined in the Clean Water Act. Mr. Stroben stated that the proposed rule covers aquatic mortality caused by impingement of organisms against cooling water intake screens, and due to entrainment of organisms in the cooling water systems.

Mr. Stroben testified that because the final rule has not been released, Duke cannot integrate the detailed requirements into its modeling process. However, for modeling purposes, Duke has assumed that the EPA will generally finalize its proposed preferred approach. Activities associated with the impingement provisions of the rule include various aquatic, technical, and engineering studies that will be required to be performed. Duke also assumes the final rule will require intake structure upgrades, such as the installation of modified intake screens and fish return systems. Duke also continues to assume that impingement mortality monitoring and numeric reporting will be required. Mr. Stroben also explained that, at this point, Duke cannot establish reasonable modeling assumptions for implementing the entrainment provisions of the proposed rule.

Proposed Coal Combustion Residuals ("CCR") Rule. Mr. Stroben testified that CCRs primarily include fly ash, bottom ash, and FGD byproducts (typically calcium sulfate (gypsum) or calcium sulfite) that are destined for disposal. Mr. Stroben stated that in June 2010, the EPA published its proposed rule regarding CCRs. The proposed rule offers two main regulatory regimes: 1) a hazardous waste classification under the Resource Conservation and Recovery Act ("RCRA") Subtitle C; and 2) a non-hazardous waste classification under RCRA Subtitle D, along with dam safety requirements. Mr. Stroben testified that both regimes would have strict new requirements regarding the handling, disposal and potential beneficial re-use of CCRs. With either potential outcome, a final rule will likely result in conversions to dry handling of ash; increased use of landfills; the closure or lining of existing wet ash ponds; and the addition of new wastewater treatment systems. Mr. Stroben testified that ultimate compliance is generally expected in the 2017 to 2019 timeframe.

Steam Electric Effluent Guidelines. Mr. Stroben testified that these guidelines govern the quality of water discharged from generating facilities. Mr. Stroben testified that after the final rulemaking, new effluent guideline requirements will be included in a station's National Pollutant Discharge Elimination System ("NPDES") permit renewals. Mr. Stroben testified that for modeling purposes, Duke assumes EPA finalizes a guideline requiring the application of FGD wastewater treatment technology, specifically bio-reactors, and prohibiting the discharge of fly ash transport water. This would require conversion to dry ash collection. He stated that Duke presumes modeled compliance is in the 2017 to 2019 timeframe.

Mr. Stroben testified that on September 20, 2013, the EPA proposed New Source Performance Standards for carbon dioxide ("CO_2") emissions from both natural gas and coal-fired electric generating units. EPA is to propose CO_2 emissions guidelines for existing fossil-fuel electric generating units by June 1, 2014, and finalize the emissions guidelines by June 1, 2015. States would submit their implementation plans for approval by June 30, 2016, with an ultimate compliance schedule currently unknown. Mr. Stroben testified that Duke does not believe that Congress will consider legislation in the near term that establishes a price on CO_2 emissions. Duke's current assumption regarding the timing of federal climate change legislation for the purpose of reflecting that potential risk in its analysis is that federal climate change legislation could be enacted in 2017 that would set a price on CO_2 emissions beginning in 2020. He explained that this timing was selected based on Duke's belief that it will be several more years before the economy recovers to the point where Congress might be willing to seriously consider climate change legislation. Mr. Stroben testified that the CO_2 prices used by Duke in its modeling are reasonable based on this outlook.

Mr. Miller described the planning process used to develop and finalize the remaining elements of Duke's plan to comply with the MATS rule. An integrated, multi-step compliance planning process was used, beginning with the development of near-term and long-term assumptions that govern the overall requirements for compliance. He stated that market information, along with cost and performance characteristics for environmental control options and new capacity resource options, were used in internally-developed screening models to narrow it down to the most viable and economic alternatives. He explained that the initial screening assessment performed during the Phase 2 planning process was not repeated, as the remaining compliance alternatives had already been narrowed down through the Phase 2 process and were relatively well defined. Duke was able to go straight into the Integrated Resource Plan ("IRP") model assessment with those options. In this step, the units' environmental control alternatives are assessed against retirement and replacement options, while still meeting reserve margin constraints.

Mr. Miller described Duke's assumed compliance requirements and how his group determines the potential investments possible in light of those requirements. Mr. Miller's group provided a reasonable combination of potential future environmental control equipment requirements, based on what Duke knows today, in order to assess the impacts of potential risks on the Phase 3 investment decisions. Mr. Miller confirmed that he provided Mr. Park the environmental compliance equipment assumption variations for the units that would accompany the assumed variations to the rules' outcomes. He explained that the only substantive changes from the Reference Scenario were for the Low Regulation Scenario, and included removing from the model the low cost placeholder FGD chemical additive systems at Cayuga and Gibson Stations, and deferring modeled Gibson selective catalytic reduction ("SCR") upgrade projects.

Mr. Miller testified that it is reasonable to use, for analytical purposes in Duke's analysis, high level cost estimates for the estimated investments (such as intake screen upgrades, dry bottom ash collection systems, and waste water treatment plants) that could be required by future environmental rules. He explained that the estimates used to reflect potential future environmental investments for purposes of modeling and analysis of the Phase 3 projects were developed using the best knowledge available, despite the significant uncertainty in the timing and ultimate requirements of the regulations themselves. He stated that these are the same or similar to the types of estimates Duke has used in recent years for modeling and analysis of environmental compliance options. They were included in the IRP model analysis as they affect the overall present value of revenue requirements ("PVRR") for the units. He stated that the costs for the MATS rule compliance options are applied in addition to these costs. Mr. Miller testified that both capital and operations and maintenance ("O&M") cost estimates for compliance with future regulations were provided to

Mr. Park for inclusion in his analysis. Mr. Miller testified that in addition to environmental compliance alternatives, his group also considered a diverse range of technology choices for new capacity resource options. He stated that he provided to Mr. Park characteristic information for new natural gas-fired combined cycle and simple cycle combustion turbines, and wind and solar resources, among others.

Mr. Miller testified that Duke would generally characterize the accuracy of the cost estimates as +30/-5%. There are a number of site specific costs that could impact the projected capital cost of a new resource option. Mr. Miller testified that the capacity option cost estimates are reasonable for analytical purposes. In addition, Duke's planning process attempts to consider all reasonable options available to meet customers' needs. He stated Duke's proposed Phase 3 Plan ensures compliance with the short-term environmental mandates, while also putting Duke in the best position possible to cost-effectively continue to serve its customers in compliance with the longer-term mandates. Mr. Miller testified that the total Phase 3 Plan capital cost estimate is approximately $113 million, without allowance for funds used during construction ("AFUDC").

Mr. Miller testified that Wabash River Unit 6 will not continue as a coal-fired generating unit due to the MATS rule. He stated that Duke is continuing to evaluate the economics and potential value of converting Wabash River Unit 6 to natural gas firing; however, a decision has been deferred until due diligence is complete.

Mr. Miller described the additional testing performed in 2013 at Gibson Station to select and validate the optimal mercury trim control technology. He testified that the results of the testing program showed that the calcium bromide reagent is very effective at enhancing mercury oxidation in the flue gas stream on the Gibson units, even at very low injection rates. The oxidized mercury is then removed by the existing FGDs to levels compliant with the MATS rule requirements. He explained that while the high temperature ACI testing performed on Gibson Unit 5 was also successful from a mercury performance perspective, very high injection rates of the activated carbon were required. This, coupled with the comparatively higher capital cost of the ACI system and potential long-term adverse effects on electrostatic precipitator operation at Gibson, make ACI less economically and operationally attractive compared to the relatively simpler and lower cost calcium bromide systems. Mr. Miller testified that through the testing and use of the portable mercury sorbent traps at Gibson Station, Duke was able to validate its baseline stack mercury measurements, confirming the need for mercury trim controls on each unit to ensure MATS compliance. Duke also re-affirmed its Phase 2 Plan component of mercury re-emission chemical systems on most of the units.

Mr. Miller also described the results of the Gibson 5 Hydrogen Chloride ("HCL") testing. He stated that until further advances in technology are made, it could not use HCL CEMS to demonstrate compliance with MATS. Also, when there is no relief duct flow, Gibson Unit 5 is in compliance with the MATS HCL limit. He concluded that once Duke eliminates this relief flow, it can demonstrate compliance with the acid gas limits via quarterly stack testing.

Mr. Miller testified that the execution of the MATS organics work practice standards did not have a significant enough impact on the mercury emissions of the Gallagher units to warrant the need for investment in additional mercury trim. Therefore, Duke does not need to invest dollars in additional MATS controls at Gallagher Station.

Mr. Miller testified that Duke believes strongly in the value of performing extensive testing before determining its compliance options because the results have allowed for complete elimination of potential MATS controls installations or otherwise make the best project selection based on economic, operational, and environmental metrics. Mr. Miller testified that for these reasons, Duke's Phase 3 Plan development was prudent and Duke plans to include the portion of these testing costs not directly assigned to a Phase 3 project as part of its Phase 3 Plan development costs to be recovered through its environmental cost recovery ("ECR") rider, as approved by the Commission's Order in Cause No. 44217.

Mr. Miller explained why each of Duke's proposed compliance options is most appropriate given what is known or reasonably knowable by Duke today. He testified that as a result of changes in the final MATS rule from the draft rule, including the option that allows a unit operator to choose between compliance with the filterable PM and non-mercury metals requirements, baghouses were no longer required for non-mercury metals-specific compliance, and Duke's compliance plan focus changed mainly to mercury. He stated that prior to the prospect of baghouses, the long-term capital plan had reflected eventual precipitator refurbishments on these units.

With the elimination of the need for baghouses under MATS, Duke re-focused its attention on the refurbishment scope. Mr. Miller testified that the precipitators are original unit equipment, approximately 35 years old, with relatively simplistic 1970s Buell design with weighted wire electrodes, a hot roof with no penthouse, and no weather enclosure. He testified that the precipitators have standard T/R sets, outdated and ineffective rapper equipment, including vibrators, and have already been sectionalized to the extent possible. In addition, this equipment has spent a substantial portion of its life operating in either a corrosive high sulfur environment from the combustion of high sulfur coals, or, also in the case of Units 3 and 4, a corrosive high sulfur environment due to the injection of sulfur trioxide ("SO_3") for precipitator conditioning in association with the combustion of lower sulfur coals.

Mr. Miller testified that, based on recent outage inspections, the Units 3 and 4 internal structural support members have severely deteriorated and are nearing failure. In addition, the widespread corrosion of the roof and casing has lead to water in-seepage during rain events. Mr. Miller explained that while all of these issues are understandable given the long life of the equipment, the precipitators on Gibson Units 3, 4, and 5 are nearing the end of their useful lives and are now technologically obsolete in the face of today's more stringent limits required for compliance. He testified that, although not definitive, there is a potential for reducing the scope of investment on Gibson Unit 5's precipitator based on initial inspection reports that indicate it is generally in better shape than Units 3 and 4. Mr. Miller stated that while Duke intends to implement all of the same key technological components of the refurbishment on Unit 5 as on Units 3 and 4, the overall project cost may be lower than the current estimate as a result of reduced structural steel or other revisions of scope. However, given the uncertainty of these potential scope reductions at this time, Mr. Park performed the IRP analysis of the Unit 5 project using the full scope cost estimate.

Mr. Miller testified that although Duke intends to control mercury re-emissions through the chemical systems approved in Phase 2, additional operating margin is still needed to ensure mercury compliance on an ongoing basis. He stated that after continued testing and evaluation of mercury trim control technologies in search of better options from economic, operational, and environmental perspectives, the calcium bromide technology (in lieu of both previously proposed and approved

ACI projects) represents the best balanced choice available for Duke and its customers. Mr. Miller explained that from an economic perspective, the calcium bromide systems are about one-tenth the cost of ACI, resulting in not only an immediate reduction to necessary capital investment, but long-term savings from reduced O&M expenses as well. Operationally, the calcium bromide system is very simple and straightforward to operate as opposed to an injection system. Lastly, the quantities of calcium bromide to be injected are de minimis compared to activated carbon, and result in no known or identified significant impacts on the waste or water processes of the plant.

Mr. Miller testified that with respect to Cayuga Station, Duke is proposing to defer ACI installation at Cayuga until it has an opportunity to test the calcium bromide after the SCRs are in service in early to mid-2015. If calcium bromide is not independently successful at Cayuga Station, Duke plans to complete the ACI installation and may explore the benefit of installing the calcium bromide system in combination with the ACI to reduce activated carbon usage. Mr. Miller testified that Duke has secured from IDEM a one-year extension of time for MATS mercury compliance at both Cayuga Station Units 1 and 2 in order to facilitate this testing and final determination. Duke proposes to update the Commission and other interested parties on the Cayuga testing and decision-making through its semi-annual ECR filings.

Mr. Miller testified regarding Duke's MATS emission monitoring and compliance demonstration plan. He stated that Duke's plan to demonstrate MATS compliance includes the installation of PM CEMS at Cayuga and Gibson Stations. These monitoring systems will be located after the existing scrubbers, allowing Duke to take advantage of the additional PM removal accomplished by the FGDs, which will result in the added benefit of eventually allowing Duke to seek exemption from opacity monitoring at these facilities. He stated that at Gallagher and Edwardsport, where no MATS-defined scrubbers are present, Duke plans to perform quarterly PM stack testing on those units. Mr. Miller testified that in addition to capital costs, estimated ongoing O&M expenses for these systems and the required testing are included in the analysis. For mercury, Mr. Miller testified that at Gibson and Cayuga Duke has re-commissioned and certified the mercury CEMS that were originally purchased for the now-vacated clean air mercury rule ("CAMR"). He stated that Duke will continue to operate those mercury CEMS for MATS compliance demonstration purposes and also proposes to maintain the portable mercury sorbent trap systems that were purchased for testing purposes as ready back-up compliance demonstration and/or mercury CEMS validation tools. The estimated O&M costs for these backup systems are included in the analysis. For Edwardsport Station, which does not have a specific mercury trim control system for which continuous emission rate feedback is needed, Mr. Miller stated that installing and operating permanent mercury sorbent trap devices is more cost effective and less maintenance intensive than installing mercury CEMS.

Mr. Miller testified that Duke's preferred approach for acid gas compliance under the MATS rule at Cayuga Station and Gibson Units 1, 2, and 3, is to comply with an alternate sulfur dioxide emission rate limit of 0.2 #/mmBTU, which can reliably meet the alternate SO_2 emission rate limit. Mr. Miller testified that Gibson Unit 4 cannot reliably meet this SO_2 emission rate limit, as it is equipped with an older scrubber that cannot achieve the removal efficiency required. Therefore, the strategy for this Unit is to perform quarterly stack emission testing for HCL, which represented the lowest cost option. Similarly, acid gas compliance at Edwardsport and Gallagher will also be demonstrated by using quarterly stack testing for HCL. He stated that ongoing O&M costs for quarterly testing of Gibson Unit 4, Edwardsport, and Gallagher is included in the analysis. Mr. Miller testified that similar to Gibson Unit 4, Gibson Unit 5 also cannot comply with the MATS acid gas limits through the alternate SO_2 limit, and is further complicated due to the presence of the flue gas pressure relief ducts on this unit. He explained that Duke has reviewed the configuration of the unit with IDEM, and the flue gas flow in the relief ducts would have to be controlled in order to use stack testing to demonstrate compliance with MATS. After considering several possible solutions to this issue, as discussed by Mr. Miller, Duke believes the lowest risk option is to physically eliminate the flue gas flow in these relief ducts. This will allow Duke to comply with the MATS rule acid gas requirements using quarterly stack testing, and will also result in actual reductions in acid gas and PM emissions. Mr. Miller further stated that this proposed approach minimizes cost by incorporating "fast-acting" damper technology that could still relieve flue gas to the stack during a malfunction event. Mr. Miller testified that to help facilitate the installation of the relief duct dampers in alignment with Duke's planned outage schedule, a one-year extension of time has been secured from IDEM for Gibson Unit 5 for MATS acid gas and PM compliance. He stated that the capital costs of the fast acting dampers and O&M costs associated with quarterly stack testing are included in the analysis.

Mr. Miller testified that in association with Duke's strategy to perform quarterly stack testing for HCL on Gibson Units 4 and 5, and also in general to facilitate improved stack access for CEMS maintenance, Duke has identified several small stack improvement projects on these units. The proposed projects include replacement of the stack elevator cars and controls with new cars that can lift heavier weights of equipment, in addition to upgrading the stack test probe support structures ("monorails") and lifting equipment to accommodate heavier and longer probe trains. He testified that these stack improvements are appropriate and necessary to facilitate MATS rule compliance demonstration in a safer, more efficient and reliable manner. Costs associated with these relatively minor but necessary investments are included in the analysis.

Mr. Miller testified regarding Duke's plan for implementing the MATS organics work practice standards. He stated that historically Duke's primary combustion tuning goal has been the minimization of NO_x emissions. However, under the new requirements, Duke must consider the emission of organic hazardous air pollutants in that tuning goal, specifically carbon monoxide ("CO"). He stated that Duke evaluated two alternatives for CO measurement – installing permanent CO monitoring equipment or utilizing temporary equipment to measure the CO during tuning events only. Mr. Miller testified that because the tuning events are performed approximately every three years, it is generally more cost effective over the long term to incur the periodic testing costs than to invest the capital cost of the permanent monitoring systems up front and also incur their ongoing maintenance costs. Therefore, the periodic O&M costs to perform this new MATS requirement are included in the analysis.

Mr. Miller testified that he believes the cost estimate and its preparation and assumptions are reasonable. Mr. Miller provided the confidential cost estimate and construction schedules associated with the Phase 3 Plan projects, noting that the largest projects for which Duke seeks approval are the Gibson Units 3, 4, and 5 precipitator refurbishment projects. Also included are the costs incurred during the testing program of the Gibson calcium bromide injection systems that directly resulted in the selection of this technology. He stated that based on the testing performed at Gibson Station, the estimated Cayuga calcium bromide testing planned for 2015 will cost between $500,000 and $1 million. If the Cayuga calcium bromide project moves forward based on this testing, those testing costs would be added to the current Phase 3 project cost estimate. If Duke does not proceed with calcium bromide at Cayuga Station, then those 2015 testing costs would be included in the Phase 3 Plan development costs in an ECR filing. Mr. Miller testified that Duke compiled its current cost estimate for its Phase 3 Plan through the use of quantity-based estimates derived by its engineering staff, actual costs experienced on recent similar projects in the Duke Energy fleet, and/or actual project bid events and contract negotiation progress. Where necessary, Duke used conservative assumptions for the escalation of certain materials and labor over the time period of its proposed Phase 3 projects and included reasonable contingency amounts (10% or more) appropriate for the level of project development and estimate classification for each project. As to the level of confidence in the Phase 3 project estimate, Mr. Miller testified that at this point in time, the Gibson precipitator refurbishment estimates should be considered as Class 2 estimates as judged by the standards set forth by the Association for the Advancement of Cost Engineering Recommended Practice 18R-97, which is an accuracy range between +5% and +20% on the high end and between -5% and -15% on the low end. He testified that as the projects' designs are fully completed and bid proposals for remaining scopes of work are received, the expected level of detail will improve to characterize a Class 1 estimate, which improves the accuracy range to within +15% to -10%. He stated that the other proposed Phase 3 Plan project estimates are considered Class 3 (with an accuracy range of +10% to +30% on the high end, and -10% to -20% on the low end), except for the Gibson Unit 5 FGD relief duct dampers project, which is currently characterized as a Class 4 estimate (with an accuracy range of +20% to +50% on the high end, and -15% to -30% on the low end). Mr. Miller testified that the Gibson Unit 5 FGD relief duct damper project does include a higher contingency amount in consideration of its state of project development. Mr. Miller testified that because of the classification of the bulk of Duke's current cost estimate as Class 2, and the fact that firm price contracts have already been awarded for the majority of the major equipment, it is reasonable for Duke to have confidence in the validity of its estimate at this time, while knowing that certainty will grow as the designs are finalized, remaining bids come in and contracts are signed.

Mr. Miller testified that Duke plans to help control the potential for cost increases and ensure the projects are completed on a timely basis by utilizing project management practices that include staffing dedicated to cost and schedule tracking, reporting, and projecting. The project team will also perform a thorough review of the engineering to ensure constructability has been taken into consideration in the final design drawings. Project and department leadership will have accountability for work within budgets and schedules. Progress for the projects will be systematically and frequently reviewed by management.

Mr. Miller testified that Duke has entered into Engineering, Procurement, and Construction ("EPC") contracts on the Gibson Units 3 and 4 precipitator refurbishment projects. With the signing of these contracts, Duke has firm price contracts on approximately 75% of the direct costs associated with the projects. He stated that Duke has also pre-negotiated pricing rates to execute the Gibson Unit 5 precipitator refurbishment, once the scope of that project is finalized. The remaining Phase 3 projects will be managed on a case-by-case basis by project engineering personnel within Duke Energy. Mr. Miller explained the identified risks and how Duke intends to mitigate the major areas of risk.

Mr. Miller described the expected O&M costs associated with the Phase 3 Plan, consisting of additional reagent costs for the calcium bromide systems; estimated equipment maintenance and operating costs for the calcium bromide and emission monitor systems; incremental costs for performing stack emission testing for PM and/or HCL on a quarterly basis; and incremental testing costs for performing combustion tuning associated with the organics work practice standards. He stated that while some of these costs are only expected to occur every few years, the approximate

O&M associated with the Phase 3 Plan is expected to be about $4 million per year, once fully implemented.

Mr. Miller testified that he provided Duke's Phase 3 Plan capital and O&M costs estimates to Mr. Park and Ms. Graft for use in their analyses. In addition, he testified that the proposed Phase 3 Plan projects meet the definitions of clean energy projects and clean coal technology as defined in Ind. Code §§8-1-8.8-2 (1)(B) and 8-1-2-6.8.

Mr. Merino described Duke's long-term load forecasting process and testified that Duke Energy's load forecast methodology is well accepted and widely used in the utility industry. Mr. Merino testified that the latest forecast for Duke points to negative growth between 2013 and 2018 for megawatt-hour ("MWH") sales and weak growth for mega watt ("MW") peaks. He stated that the weak outlook in sales is attributable to a slow economic recovery, low levels of new customer additions, the impact of energy efficiency programs, and the expiration of wholesale backstand contracts associated with the Gibson 5 ownership. If the impacts of energy efficiency programs are excluded from the sales and peak forecasts, the expected 5 and 10 year growth rates are positive. Mr. Merino testified that Duke's Core and Core Plus energy efficiency programs are included in the load forecasting process. Mr. Merino testified that the projected long-term growth rates for energy sales reflected in the most recent forecast for Duke's service area are comparable to those of the 2011 State Utility Forecast Group's forecast for the entire state of Indiana for the residential and commercial segments; Duke shows slightly lower growth rates for the its industrial sector. Mr. Merino testified that Duke's peak demand forecast is developed to represent projected peaks before demand response load reductions. In addition, the load forecast has not been reduced for the projected impact of load control available to certain retail customers served under special contracts. Mr. Merino testified that this information is separately provided to the IRP Group.

Mr. Merino testified that in addition to the base forecast, Duke developed high and low sensitivities for energy sales and peak demand projections by combining alternative views of economic indicators and the probability distribution of estimated forecast errors. He testified that the use of alternative economic projects is the main driver of the high and low deviation from base for the first few years of the forecast. For year six and beyond, the high and low forecasts were developed by applying the standard error of the regression models and using a 95% confidence interval. Mr. Merino testified that the load forecast uncertainty grows throughout the forecast period and is not symmetrical with regard to the base forecast. He explained that there is more downside risk to the base case forecast because the potential impact to energy sales from technology improvements and energy conservation is negative, while the potential impact on energy sales from economic growth uncertainty can be either positive or negative. For example, the high case peak demand in 2015 is expected to be 116 MW or 1.8% higher than the base case, while the low scenario is expected to b -165 MW or 2.5% below the base case peak demand. By 2025, the high scenario peak demand is 429 MW or 5.6% above the reference case and the low scenario peak demand is -447 MW or 5.8% lower than the reference case. Mr. Merino testified that Duke's load forecast is reasonable and adequately considers EE impacts.

Mr. Merino testified that Energy Ventures Analysis, Inc. ("EVA") produced the 2013 Duke Energy fundamental forecast. He explained how Duke Energy chose EVA and the process used in developing the fundamental forecast. Mr. Merino testified that, in his opinion, the fundamental forecast prepared by EVA is a reasonable view of future energy, coal and gas prices.

Mr. Park described Duke's 2013 IRP analyses and results.[1] He explained that three discrete and internally consistent scenarios that cover a wide range of possible futures were developed (Reference, Low Regulation, and Environmental Focus). Once the specific modeling assumptions for each scenario were determined, a capacity expansion model was used to develop an optimum portfolio for each scenario. The three portfolios were then analyzed under each scenario and under a range of sensitivities within each scenario. Finally, the portfolios were compared for robustness by examining the results of the scenario and sensitivity analyses. Mr. Park explained that scenarios are alternative views of the future, whereas sensitivities vary one assumption within a scenario. He stated that sensitivity analysis provides a secondary level of analysis concerning the expected behavior of a portfolio in response to independent changes in key variables. He explained that while changing a single variable is not realistic in terms of measuring a specific dollar impact, it does give insight into the risk factors of a given analysis.

Mr. Park explained the major assumptions in the three scenarios. In addition to the environmental regulation assumptions used for the Reference Scenario, as discussed by Mr. Stroben, alternative environmental assumptions were developed to coordinate with the general themes of the other two scenarios. These alternate assumptions generally changed the timing of requirements and/or the severity of the requirements. Mr. Park also described the models and modeling methodology used for the IRP analyses.

Mr. Park testified that the Blended Approach Portfolio was selected as the preferred plan in the 2013 IRP. This plan includes the following: (1) retirement of Wabash River Units 2-5 in 2015 due to MATS; (2) conversion of Wabash River Unit 6 to natural gas in 2016; (3) retirement of Connersville and Miami-Wabash oil-fired combustion turbines ("CT") in 2018, and retirement of Gallagher Units 2 and 4 in 2019; (4) addition of 800 MW of natural gas-fired CT capacity between 2019 and 2025; (5) 680 MW of natural gas-fired CC capacity between 2027 and 2030; (6) 280 MW of nuclear capacity in 2031; and (7) 2,344 MW of renewable capacity between 2019 and 2033. Mr. Park explained that no firm decisions have been made at this time concerning Wabash River 6 and Gallagher or the capacity additions, although each of the capacity additions can be considered a "placeholder" for the type of capacity needed on the system. He stated that the plan also includes the assumption that Duke will meet the 11.9% energy efficiency ("EE") target by 2019 and maintain 11.9% EE as a percentage of retail sales throughout the study period as the load grows. Mr. Park testified that the near-term environmental controls in the plan were Cayuga 1-2 SCRs and the Phase 3 Projects including Gibson 3-5 precipitator refurbishment, Gibson 5 FGD fast-acting dampers, mercury trim technology at Gibson and Cayuga, and compliance monitoring equipment on all units. The plan also included other expected future environmental compliance equipment additions as a result of anticipated rules and regulations.

Mr. Park described the additional analyses performed regarding Duke's Phase 3 Plan needed to comply in the short and longer term with the MATS rule, and the result of those analyses. He stated that the additional scenario and sensitivity runs were performed to compare Phase 3 Plan environmental compliance investments versus retirement for each unit included in this filing, using the selected 2013 IRP. The primary analysis performed was to compare the PVRR with the environmental controls to the PVRR with the unit retired in 2015 under the base conditions for each

[1] Duke submitted its 2013 IRP to the Commission on November 1, 2013, and also filed a Petition requesting to keep certain portions of its IRP confidential in Cause No. 44414. On November 12, 2013, Duke filed a Motion for Administrative Notice of its 2013 IRP in this proceeding.

of the three scenarios. The secondary analysis performed compared these cases under various sensitivity conditions. He explained that for the retirement analysis, Duke used the System Optimizer model to re-optimize the capacity additions necessary to replace the retired capacity. Duke then ran the Planning and Risk model for both the case with controls and the retirement case to obtain more detailed production costing information.

Mr. Park explained the differences in the analyses performed for different units in the Phase 3 analysis. In addition, he stated that High CO_2 price sensitivity was performed only for the Environmental Focus Scenario. Mr. Park testified that for the Phase 2 analysis, Duke only had one internally consistent scenario, so sensitivity analysis was necessary to test the robustness of the assumptions. However, for the Phase 3 analysis, Duke has changed its process by using three internally consistent scenarios to study a broader range of potential future outcomes. He stated that the scenario analysis results provide a much better picture of the economics of an investment and the sensitivity analysis becomes more of a secondary check and should be viewed as providing directional insights. Mr. Park testified that Duke considered renewable energy resources and the purchase of market capacity in its analyses.

Mr. Park testified that although Duke modeled other environmental compliance equipment additions beyond the Phase 3 projects, the modeling shows that calcium bromide injection and PM CEMS on Gibson Units 1 and 2 is more economical than retiring them in all three scenarios. Similarly, the modeling shows the Gibson Units 3 and 4 precipitator refurbishment, calcium bromide injection, and PM CEMS, as well as stack improvements for Gibson Unit 4 are more economical than retiring them in all three scenarios.

Mr. Park testified that under all three scenarios, which include internally consistent assumptions and cover a broad range of potential futures, adding the Phase 3 Projects at Gibson Unit 5 is economical. Mr. Park testified that for Gibson Unit 5, the Low Regulation Scenario showed the Phase 3 Plan to be more economical than retirement. For the Reference Scenario, the projects were more economical than retirement in the Low Coal, High Gas, High Load, and High Capital sensitivities, while retirement was more economical in the Low Load, Low Gas, and High Coal sensitivities. For the Environmental Focus Scenario, the projects were more economical than retirement in the Low Coal, High Gas, and High Load sensitivities, while retirement was more economical in the High Capital, High CO_2, Low Load, Low Gas, and High Coal sensitivities.

Mr. Park testified that while Duke does not expect any of these variables to change independently from the other variables, it does direct attention to the impacts of fuel and carbon prices. He stated that in the process of developing the three scenarios, Duke quantified several of these interrelationships that mitigate some of the risks that the sensitivity analyses suggest.

Mr. Park explained that model runs comparing ACI at Cayuga Units 1 and 2, based on the Phase 2 Compliance Plan, to calcium bromide injection showed that calcium bromide is clearly more economical for customers. Replacing ACI with calcium bromide at Gibson 5 is similarly more economic. Mr. Park also testified that the modeling shows the Cayuga Phase 3 investments are cost effective in all three scenarios versus retirement in 2015.

Ms. Graft testified that Duke is requesting authority to recover the retail jurisdictional portion of the actual costs of the Phase 3 Plan through Riders 62 and 71. Duke is also requesting authority to accrue a regulatory asset for post-in-service carrying costs at a rate equal to Duke's

AFUDC rates on the retail jurisdictional portion of the capital project expenditures for the Phase 3 Plan once the projects are placed in service until the costs are included in retail rates. She testified that, in addition, Duke is requesting authority for the use of accelerated depreciation rates for the capital projects that are part of Duke's proposed Phase 3 Plan once they are placed in service.

Ms. Graft explained that upon approval of the Phase 3 Plan projects as Qualified Pollution Control Property ("QPCP"), Duke is proposing to commence construction work in progress ("CWIP") ratemaking treatment for the Phase 3 Plan projects via Rider 62 (currently filed in Duke's ECR proceeding, Cause No. 42061 ECR). She stated that Duke will continue this ratemaking treatment until the Commission determines these projects are used and useful in a proceeding that involves the establishment of Duke's base retail electric rates and charges. Ms. Graft explained that Duke is requesting approval to include the retail jurisdictional portion of depreciation and incremental O&M expenses resulting from the Phase 3 Plan in Rider 71. She stated that recovery of these costs will remain in Rider 71 until the amounts are moved to base rates in a retail base rate case proceeding. She stated that the O&M costs will include both reagent costs and non-reagent costs. Duke also requests deferral of depreciation and incremental O&M expenses associated with the Phase 3 Plan projects on an interim basis until such costs are recovered in Rider 71. Ms. Graft testified that Duke is requesting authority to defer and subsequently recover the retail jurisdictional portion of plan development, engineering, testing, and pre-construction costs associated with future environmental planning for compliance with air, water, or waste regulations via Rider 71 (or via Rider 62 to the extent such costs are related to a capital project). Ms. Graft testified that Duke is proposing to use a 20-year recovery period (or shorter if the normal life of the asset is shorter) and a 10% negative net salvage factor in developing the depreciation rate for its Phase 3 Plan projects. The resulting depreciation rate, including the adjustment for negative net salvage, is 5.5%.

Ms. Graft testified that the average retail rate impact of the Phase 3 Plan is estimated to be a 0.8% increase over total retail revenues for the twelve months ended September 30, 2013. She explained that this rate impact may be slightly understated because it does not include the AFUDC that will accrue while the projects are under construction of approximately $3 million. Ms. Graft explained that customer rates would have been an additional 2.0% to 2.5% higher in 2017 (in addition to the 0.8% increase for the Phase 3 Plan projects) had Duke proceeded with ACI at Cayuga, Gallagher, and Gibson Stations as originally proposed in the Phase 2 Plan. Ms. Graft testified that the accounting treatment proposed by Duke for post-in-service carrying costs is in accordance with Generally Accepted Accounting Principles ("GAAP").

6. <u>OUCC Direct Testimony</u>. Mr. Alvarez discussed the changes in Duke's Phase 2 Plan projects approved by the Commission in Cause No. 44217. He stated that Mr. Esamann testified the significant change in its Phase 2 Plan and MATS compliance plan is that these plans no longer include ACI as a primary technology option; through continued testing and evaluating of mercury control trim technologies, Duke gained confidence in the calcium bromide ("$CaBr_2$") system; the $CaBr_2$ system is a better technology, and operationally, environmentally, and economically superior to the ACI System; and in both capital and O&M costs, the $CaBr_2$ system is approximately one-tenth the cost of the ACI System.

Mr. Alvarez testified that the $CaBr_2$ system is a different technology than the ACI system previously approved by the Commission in Cause No. 44217, and the technology switch represents a fundamental change in Duke's Phase 2 Plan MATS compliance strategy approved in Cause No. 44217. He explained that the ACI system injects activated carbon and captures mercury in the flue gas (along the flue ducts) while the alternative $CaBr_2$ system sprays fuel additive over coal before it is fed to the burners to enhance mercury ("Hg") oxidation downstream. He stated that the combination of SCR and $CaBr_2$ systems oxidizes or ionizes mercury, leaving little or no elemental mercury in the flue gas for the ACI to capture, and therefore, rendering the ACI redundant and unnecessary. Mr. Alvarez testified that if Duke cancels any of the approved ACI systems, it should request a modification of its previously granted certificate of public convenience and necessity ("CPCN") to reflect the cancelled ACI and corresponding reduction to the previously approved funding. He stated that if any utility decides to change significantly the CPCN approved by the Commission, it should seek approval for such a modification.

Mr. Alvarez testified that the OUCC is concerned that Duke did not seek to amend its CPCN despite fundamental changes it made in its MATS compliance strategy after the Commission approved Duke's Phase 2 Plan in Cause No. 44217. First, the technology change from that approved by the Commission requires a modification to the CPCN granted, and is not the type of change that should be tracked through the ECR. In addition, Duke's choice of the $CaBr_2$ fuel additive over the ACI system results in a decrease in funding needed to comply with MATS.

Mr. Alvarez explained that the funding approved for the Phase 2 Plan included amounts for construction, preliminary engineering, testing, and pre-construction, etc., for the ACI systems in Cayuga and Gibson Stations. He stated that in this proceeding, Duke proposes to defer the ACI systems on Cayuga and cancel the ACI system on Gibson Unit 5, while maintaining the funding for the cancelled ACI system for Gibson Unit 5, which is inconsistent with the Commission's Order to set a construction cost limit in Cause No. 44217. Mr. Alvarez testified that if Duke does not seek to amend its CPCN and modify the funding for the cancelled ACI system on Gibson Unit 5, it will have an additional level of funding not approved by the Commission.

Mr. Alvarez provided a table titled "Modification of CPCN – Phase 2 Plan" showing the "OUCC Recommended Total Phase 2 Plan Construction Costs" amount. He recommended the modification of Duke's CPCN to reflect the cancellation of the Gibson Unit 5 ACI system and the approved CPCN cost estimate for "The Total Phase 2 Plan Construction Costs" to the "OUCC Recommended Total Phase 2 Plan Construction Costs" amount.

Mr. Alvarez stated that Duke's proposed refurbishments will require extensive work for the electrostatic precipitators ("ESP") on Gibson Units 3, 4, and 5, and the roof and inside of the ESPs will be fully removed. He explained the Duke anticipates that only the support structure and the side walls of each ESP will remain post-refurbishment, but the exact scope will vary for each unit. He testified that Duke did not provide cost breakdown details for the ESP projects. He stated that the OUCC requested the cost estimate in electronic format with formulas intact. However, Duke's response provided a copy of the Phase 3 project estimates Duke previously attached to Mr. Miller's direct testimony in this Cause.

Mr. Alvarez testified that the OUCC sought additional information from Duke regarding the EPC contract for the ESP projects. He stated that Duke provided a document identifying the winning bidder and bid amount for the Gibson Units 3, 4, and 5 Precipitator Refurbishment Projects. He stated that the OUCC analysis of the bid information determined there was an 18% difference between the estimated total "Direct Costs" of the three (3) ESP refurbishment projects and the winning bid Duke received for the same projects. He explained that if Duke receives Commission approval for its cost estimate, additional funding of approximately 18%, resulting from the difference between the winning bid and the total "Direct Cost," becomes available to Duke. He added that the ESP Refurbishments represent approximately 90% of Duke's total funding request in this Cause.

Mr. Alvarez testified that the OUCC is not recommending the Commission remove the 18% additional funding from Duke's Phase 3 Plan request, as the additional 18% would act as a financial buffer for the Phase 3 Plan projects. He explained that if Duke is allowed to keep the 18% additional funding, the OUCC recommends that the Commission approval of the project costs include a cap and find that the project costs should not exceed those cost estimates listed in Duke's Confidential Exhibit C-1: Phase 3 Projects, and Duke's Confidential Exhibit C-2: Phase 3 Plan Cost Estimate Detail.

Mr. Alvarez testified that the OUCC has additional concerns with and recommends changes to Duke's Phase 3 Plan project cost estimates. He provided Table VI-I: ESP Refurbishment EPC Contract that reflected the "Additional Available Funding" resulting from the difference between the "Estimated EPC Contract" (or Total Direct Cost) and the "Winning Bid" (or EPC Contract Price) amounts of the Gibson Station ESP Refurbishments Projects in the Phase 3 Plan. He also provided Table VI-2: Phase 3 Plan Project Cost Estimates to reflect changes in Duke's Phase 3 Plan project cost estimates. He stated that the OUCC recommends that Duke reflect the EPC Contract Price on the total "Direct Cost" estimate and the Additional Available Funding amount on the total "Duke Indirects and Overheads" cost estimates. He also stated that the OUCC recommends the Commission deny Duke's proposed IGCC Sorbent Trap project and remove the project's cost estimate from Duke's proposed Phase 3 Plan Total Estimated Costs.

Mr. Alvarez stated that the OUCC has concerns regarding Duke's general plan for MATS compliance. He testified that although Duke did not include Wabash River Unit 6 topics in this Cause, the OUCC has previously expressed concerns on this unit and reiterates those same concerns here. He explained that Duke has not announced its plans for Wabash River Unit 6, and as the MATS compliance deadline approaches, Duke will have fewer opportunities for alternative compliance solutions regarding Wabash River Unit 6 environmental compliance. He stated that the OUCC is expressing this concern as part of its overall review of Duke's MATS compliance for all its units.

Mr. Alvarez summarized the OUCC recommendations regarding Duke's request in this Cause. He testified that the OUCC recommends the Commission:

1. Amend the CPCN approved in Cause No. 44217 to reflect the technology change in Duke's MATS compliance strategy from the ACI system to the $CaBr_2$ system;

2. Reflect Duke's cancellation of the Gibson Unit 5 ACI system, and reduce the cost estimate for "The Total Phase 2 Plan Construction Costs";

3. Order Duke to seek modification of the CPCN (Phase 2 for the ACI or Phase 3 for the $CaBr_2$) corresponding to the system not chosen, and seek modification within sixty (6) days of making the final commitments regarding the technology of choice;

4. Deny Duke's request for the IGCC Mercury Sorbent Trap and remove its funding from the Phase 3 Plan cost estimate;

5. Reduce the total "Direct Cost" in Phase 3 Plan cost estimate to reflect the EPC Contract Price for the Gibson Units 3, 4, and 5 ESP Refurbishment projects;

6. Reduce the "Total Phase 3 Plan Construction Costs" to reflect the removal of the IGCC Mercury Sorbent Trap project and the EPC Contract Price of the ESP Refurbishment projects for the Gibson Station; or include the 18% Additional Available Funding amount to the "Duke Indirects and Overheads";

7. Approve the cap on the "Total Phase 3 Plan Construction Costs" to reflect the removal of the IGCC Mercury Sorbent Trap project and inclusion of the 18% Additional Available Funding to the total "Duke Indirects and Overheads";

8. Accept the OUCC's estimate of the Original Cost and Net Original Cost for the Gibson ESPs included in Duke's base rates, rate impact, and ESP cost recovery treatment; however, should the Commission approve any form of rate recovery in this Cause for the Gibson ESP Refurbishment projects, then the OUCC recommends a cap on recovery (excluding AFUDC); and

9. Order Duke to provide an update regarding its plans for the Wabash River Unit 6 within sixty (60) days of the date of the order.

Mr. Eke testified on his condition assessment of the units in Duke's Phase 3 Plan. He described Duke's Gibson Unit 3, 4, and 5 ESPs as 1970s Buell design type, chevron gas flow bare weighted wire. He stated that Units 3 and 4's ESPs have sixteen (16) 45 kV standard transformer rectifiers ("T/R") per box, with two (2) boxes per unit and 160 rappers per box. He added that Unit 3 ESP has magnetic-impulse gravity-impact ("MIGI") type and Unit 4 and 5 ESPs utilize MIGI rappers on plates and vibrators.

Mr. Eke summarized the assessment of the Gibson ESPs, Unit 5 Stack, and FGD Upgrade. He testified that Duke provided a PECO Company ESP Inspection Report completed on November 5, 2013, and the report found that the overall condition of the collecting plates and support system are satisfactory, and do not require replacement or upgrade at this time; the casing and structure of the ESP are in good condition and do not require any major upgrades, based on internal observations as well as external ultrasonic thickness testing; the ESPs were in a dirty state with large amount of fly ash build-up on the collecting plates and discharge electrodes due to poor rapping, and upgrades are needed in this area; and the lower collecting plate B-line system has the most apparent and widespread problem, and if not replaced will lead to a significant amount of permanent damage and internal issues.

Mr. Eke stated that PECO's recommendation was to replace all lower collecting plate B-line bars; replace all insulator compartment "doghouse" roofs; replace all High Voltage System Vibrator Rappers with MIGI Rappers; replace all wire discharge electrodes with rigid style electrodes for increased performance and reliability; replace all traditional T/R Sets with High Frequency "Switch mode" Power Supply for increased performance; and replace all Anvil Beam Hanger Bolts for future reliability. Mr. Eke testified that the OUCC considered the PECO ESP recommendations as reasonable because these will take care of old and obsolete sections of the ESPs. He stated that

Duke's Phase 3 Plan addresses the recommendations of the inspection report and it is now reasonable to replace the internals to take advantage of new technology.

Mr. Eke testified that Duke provided a Sargent & Lundy ("S&L") inspection report completed in November 2010 for the Unit 5 Stack. He stated that the S&L report found the following: the Concrete Shell Exterior showed no sign of degradation and therefore requires no remedial action at this time; the Concrete Shell Interior appeared to be in good condition, but there were signs of water seepage underneath the aviation lights and test door access which S&L recommended Duke repair the gunite lining and continued monitoring; the Platforms and Ladders clips should be replaced, including expansion boot of the Breeching Ducts; the overall chimney is in good condition and the lighting systems of the continuous emission platform need few repairs; and the pressure sensor fans should be made operable.

Mr. Eke described the FGD Duct Dampers and their principal functions. He stated that a damper can modulate gas or airflow, bypass airflow into an alternative duct system, or isolate a process (usually for inspection and repair). He testified that in the scrubber section, there is a high chance that a pipe will partly block or twist in a way that will divert a jet of gypsum onto ducts and dampers; ash in interior spaces can be deposited in the ducts and damper surfaces; and undesirable concentrations of contaminants can cause corrosion to the interior of the unit.

Mr. Eke testified that the Unit 5 FGD relief duct dampers need replacement. He stated that replacing the duct dampers reduces acid gases and particulate matter (PM) emission by ensuring that all flue gas passes through the scrubber, and in his experience and research, duct dampers wear out or warp under constant flue gas flow and lose the ability to function properly.

Mr. Eke testified that the ESPs need refurbishment for continued performance. He stated that the PECO report shows that the internal structures of the ESPs are corroded but continued to control opacity and particulate emission at 70% of PM compliance limits. He explained that Duke plans to replace Gibson Units 3, 4, and 5 ESPs to meet the filterable PM standards for MATS compliance. Mr. Eke testified that the OUCC supports the ESP refurbishments and opined that without the refurbishments, Duke's filterable PM compliance will be interrupted and some of the ESPs internal structure problems will be exacerbated.

Mr. Eke explained the reasons for the performance problems described in the inspection report. He testified that the ESPs' operating and performance problems can be categorized into dust buildup, rapper failure, and corrosion of structural members. He explained that some problems are related to inherent ESP design limitations and age, and corrosion problems can be attributed to hot operating environment combating against the elements, maintenance procedures, or a combination of both.

Mr. Eke testified that the failure of the rapping system is the usual cause of dust buildup on the collection plates or discharge wires. He explained that under normal operating conditions, dust is collected and allowed to buildup on the plates for some specified timeframe to take advantage of certain cohesive forces between particles and that the rapping system must provide sufficient force to dislodge the dust without damaging the ESP or cause excessive re- entrainment. He stated that sticky dust or dew point conditions could result in excessive dust buildup.

Mr. Eke testified that the relative age of rappers and vibrators limit the ESPs' ability to cope effectively with high dust accumulation. He explained that the reasons for rapper failures depend on the rapper type, and the MIGI rappers used in the Gibson ESPs can fail because of a short circuit in the coil that lifts the rappers. He stated that corrosion from weather elements can create air gaps between rapper seals and cause vibrators to fail; hammer failures are difficult to diagnose; and motor and gear reduction systems fail. He added that Duke's inspection report mentioned several collecting system failures throughout the Gibson ESPs.

Mr. Eke testified that corrosion is expected because the Gibson units do not have penthouses, the compression insulators were housed in long narrow compartments with open roof, and there is evidence of water leakage from the roof. He explained that Duke's inspection report showed corrosion concentrated at the top of the units and on the interior collecting plates, which jeopardize the plates' collection efficiency. He testified that lower collection efficiency resulted from a collecting plate breaking open, and the gas flow and consequent velocities through the precipitators were no longer according to design. Mr. Eke testified that he has no concerns regarding the condition assessment report and the report's conclusion that the overall conditions of the ESP units' internals need replacement.

Mr. Eke testified that Duke considered the Gibson refurbishment as a Class 2 Estimate (+30% to 70%) of project definition, and awarded the contract to an EPC contractor. He stated that the calcium bromide system, PM CEMs, and Stack improvements estimates were Class 3 estimates (+10% to 40%), while the FGD relief duct dampers estimate was Class 4 (+1% to 15%). He explained that the construction will take approximately 24 months, including the in-service date, and the facilities will remain operational during construction. Mr. Eke testified that the cost estimates for the refurbishments were reasonable. He explained that Duke applied the standard set by the Association for the Advancement of Cost Engineering ("AACE") Recommended Practice 18R-97, and awarded the refurbishment contract.

Mr. Eke noted that the estimate class for the ESP refurbishment was not precise, taking into consideration the fact that the contract has already been awarded. He explained that since Duke already awarded the ESP refurbishment contract (including the Unit 5 FGD duct dampers and stack improvements) to SEI, an EPC contractor, Duke should consider the ESP estimate a class 1 instead of a class 2 estimate. He stated that as a class 1 estimate, the expected accuracy range should be between -3% to -10% on the low end, and +3% to +15% on the high end instead of the -5% and -15% on the low end, and +5% to +20% on the high end stated by Mr. Miller. He explained that the bid and the award cost is less than the direct refurbishment cost that Duke is asking for, and it is fair to state that there is an 18% contingency in the ESP refurbishment estimate to take care of any unanticipated events to take care of the projects. He testified that the OUCC recommends a cost cap on the Gibson ESP Units refurbishment including the Unit 5 FGD duct dampers, and stack improvements cost estimate at the proposed cost exclusive of AFUDC.

Mr. Eke testified that the Gibson 5 FGD duct damper estimate is acceptable. He explained that the Gibson 5 FGD relief duct damper is a Class 4 estimate with a high contingency built into the estimate that makes up for the low accuracy range of -15% to -30% on the low end and +20% to +50% on the high end. He stated that it is not possible to state that the FGD relief duct damper project estimate is a reasonable cost estimate without evaluating the itemized list cost breakdown of the labor, material, and equipment.

Mr. Eke recommended that the Commission cap the Gibson ESP Units refurbishment including the Unit 5 FGD duct dampers, and stack improvements cost estimate at the proposed cost exclusive of AFUDC; and approve the Phase 3 Plan projects at the proposed cost estimate excluding AFUDC.

Ms. Armstrong testified regarding pending environmental regulations impacting the electric industry, including MATS. Ms. Armstrong testified that the Phase 3 Plan was necessary for Duke to comply with MATS, but the OUCC opposed the cost recovery of some of the Plan's costs. She specifically noted the OUCC's conditional approval of the $CaBr_2$ systems at Cayuga Units 1-2 and disapproval of the Edwardsport mercury monitors for cost recovery under Duke's Rider Nos. 62 and 71.

Ms. Armstrong noted that the OUCC was concerned that Duke's proposal for $CaBr_2$ systems on Cayuga Units 1 and 2 may be over complying with MATS at the ratepayers' expense. However, she stated that the OUCC did not want to discount using $CaBr_2$ for mercury control at Cayuga when the $CaBr_2$ testing at Gibson showed such promising reductions in mercury emissions. She said that $CaBr_2$ will become a viable option for mercury control at Cayuga once the SCRs are complete and operational. She noted that if Cayuga experiences the same mercury reduction results as the $CaBr_2$ tests at Gibson, $CaBr_2$ systems on Cayuga would cost much less to install and operate than the ACI system previously planned for the facility, resulting in lower compliance costs for Duke's ratepayers. In order to allow Duke to pursue this technology, she recommended that Commission approval of the $CaBr_2$ systems on Cayuga Units 1 and 2 be conditional upon removing the ACI systems and their estimated costs from the Phase 2 Plan if testing demonstrates the $CaBr_2$ system is able to remove mercury at the levels necessary for MATS compliance. She also recommended that Duke report to the Commission with its final $CaBr_2$ test results once they become available.

Ms. Armstrong stated that the OUCC considers the cost of the mercury monitors at Edwardsport to be a part of the IGCC plant costs included in the cost cap set out in the settlement for Cause No. 43114 IGCC 4S1. She stated that Duke should have known before the Edwardsport IGCC plant began construction or design that the plant would be required to continuously monitor its mercury emissions, and the cost of the mercury sorbent traps (or any other mercury monitoring device) should have been included in the original and subsequently updated cost estimates for the IGCC facility. Therefore, she concluded that the IGCC mercury sorbent traps are subject to the hard cost cap set forth within Section 2 of the Settlement Agreement approved by the Commission in Cause No. 43114 IGCC 4S1, and should not be permitted to be recovered through Duke's QPCP Rider No. 62.

She noted that when Duke began planning the Edwardsport IGCC plant in the 2006-2008 timeframe, the final CAMR that mandated new coal-fired electric generating units ("EGU") to monitor and control their mercury emissions was in effect. She testified that under CAMR, new IGCC units constructed after January 30, 2004, were required to meet a mercury emission standard of 20×10^{-6} lbs/MWh. To show compliance with the standard, she explained, CAMR required new units to install and operate either mercury CEMs or mercury sorbent traps. She further noted that the Edwardsport IGCC plant's initial Title V Operating Permit included these emission and monitoring standards. She argued that even though CAMR was vacated by the time the IGCC facility began construction in May 2008, Duke knew that it would be required to control and monitor Edwardsport IGCC mercury emissions eventually under Section 112 of the CAA. She showed that the IGCC plant's most recent Title V Operating Permit Renewal also included mercury emissions standards and monitoring requirements. Based on these reasons, Ms. Armstrong recommended disapproval of the Edwardsport mercury monitor costs.

Mr. Rutter testified regarding his review of Duke's 2013 IRP and how the IRP impacted Duke's MATS compliance strategy. He discussed the primary analyses used in the 2013 IRP and whether or not those IRP scenarios were the most reasonable on which to base the 2013 IRP and the subsequent Phase 3 Plan development.

Mr. Rutter expressed his concerns regarding whether the IRP scenarios Duke selected to model were the most appropriate scenarios to adopt in developing the IRP and in assessing the Phase 3 Plan economics. He noted that in its extensive modeling of its IRP, Duke presented no evidence in its case-in-chief that the IRP scenarios were either the most realistic or best fit scenarios for 2013 IRP development. Mr. Rutter stated that without that evidentiary support, an analysis of the economics of the Phase 3 Plan is more complicated.

Mr. Rutter stated that during 2013, he participated as part of the OUCC team in the Duke 2013 IRP stakeholder process. In that process Duke polled the attending stakeholders to develop two alternative scenarios that would supplement Duke's internally developed scenario for modeling purposes. In the IRP process, two alternative scenarios were developed based on stakeholder consensus. As part of his Phase 3 Plan evaluation, Mr. Rutter wanted to make sure that while the scenarios were based on stakeholder consensus, that they also represented reasonable bookends producing representative alternative scenarios and modeling. Mr. Rutter stated that the absence of evidence or testimony from Duke as to why the IRP scenarios were the most reasonable in developing the 2013 IRP raised his concerns regarding the IRP's validity and the economics utilized by Duke in developing the Phase 3 Plan.

To alleviate his concerns regarding the validity of the IRP scenarios utilized by Duke, Mr. Rutter requested information from Duke regarding the IRP development, the Phase 3 Plan economics, whether or not other scenarios were examined, and if so, why they were rejected. He also spoke with Duke witnesses Park and Merino to further discuss why Duke believed the IRP scenarios were the most appropriate for developing the 2013 IRP and why these scenarios, when modeled, would validate the economics of the Phase 3 Plan. These discussions and data responses alleviated his concerns, as the information provided him with sufficient support to accept the scenarios as appropriate and reasonable for the development of the 2013 IRP, and to validate the economics of the Phase 3 Plan. These answers provided support that of the three scenarios modeled, the two alternate scenarios developed during the IRP process provided extreme bookends to the Duke Plan and encompassed the full spectrum of possibilities that could have been developed.

Regarding why he thought it was is necessary to develop the estimated cost of the Gibson Units' 3, 4, and 5 ESPs included in Duke's current base rates, Mr. Rutter noted that as explained in the direct testimony of OUCC Witnesses Alvarez and Blakley, Duke is seeking to recover the Phase 3 Plan cost through its ECR tracker. Since Phase 3 encompasses the replacement or retrofit of all or a portion of the existing ESPs, Mr. Rutter testified that it is the OUCC's position that the value of the retrofitted or replaced facilities must be netted against the value of the new retrofitted or replacement facilities, or ratepayers will be required to pay rates on facilities that are no longer used and useful.

Mr. Rutter stated that Duke did not provide the information needed by OUCC witnesses Alvarez and Blakley to determine the validity of Duke's proposal relative to the existing Gibson

Units 3, 4 and 5 ESPs until February 12, 2014. Mr. Rutter stated that he developed a reasonable estimate of the ESPs' net original cost as of May 31, 2003, which was the rate base cut-off date from Duke's last rate case, Cause No. 42359.

Mr. Rutter testified that he reviewed the testimony and exhibits filed in Cause No. 42359 to extract relevant information that could provide the ESPs' net original cost. While he was unable to precisely determine the net book value/original cost of the ESPs as of May 31, 2003 in response to OUCC data request 1-23 in this Cause, Mr. Rutter stated that Duke provided the latest depreciation rates for Gibson Units 3 and 4 and Gibson Unit 5: 3.69% for Gibson Units 3 and 4 and 2.94% for Gibson Unit 5. Once he determined the effective depreciation rates, he obtained Duke's estimate of the original cost of the ESPs for Gibson Units, 3, 4 and 5. Mr. Rutter stated that the estimated net original cost combined as of May 31, 2003 for the Gibson Units 3, 4 and 5 was $5,708,543. Mr. Rutter concluded that is this amount that is currently included in rates that the OUCC is requesting be credited against rate base.

Mr. Blakley testified that Duke is requesting to recover the retail jurisdictional portion of the actual costs of its QPCP investments related to its plan to comply with the EPA's MATS rule, referred to as its Phase 3 Plan. Mr. Blakley explained that Duke will recover the costs through Rider 62, which provides recovery for CWIP, and Rider 71, which provides recovery for depreciation and operation and O&M.

Mr. Blakley stated that the major part of Dukes request is the "refurbishment" of Gibson Units' 3, 4, and 5 ESPs, and that this is basically a replacement of ESPs that are included in base rates. He stated that the order in Duke's last base rate case was May 18, 2004 and that Duke has been earning a return on and a return of the ESPs included in base rates since that time.

Mr. Blakley explained that Duke did not recognize or propose a solution in its case-in-chief that would address the problem of having ESPs out of service and included in base rates, while at the same time recovering the new replacement ESPs' costs in its ECR tracker. He said that the Commission has addressed the problem of replaced environmental equipment before in NIPSCO Cause No. 42150 ECR 21. He noted that the Commission recognized in that order, the inherent problem of over–recovery that occurs when a utility earns a return on an investment in base rates while at the same time earning a return on its replacement investment in a tracker. Mr. Blakley also referred to Indiana-American Cause No. 42351 DISC 1, another case where the Commission recognized that an investment included within base rates should be recognized for ratemaking purposes when it is replaced and the cost recovery of the new replacement is included within a tracker. He said that the Commission stated in its final order in that Cause "if retirements are ignored and a utility is allowed to earn a return on a new plant through a DSIC, they will collect a return on the fair value rate base determination from the last rate case."

Mr. Blakley explained that the OUCC made a "best estimate" of the original cost of the ESPs included in base rates. He proposed that the estimated net original cost of Gibson's Units 3, 4, and 5 ESPs be netted against the new ESP investment in Duke's ECR tracker, thus reducing the return and depreciation expense calculated on the new investment. He stated that this will provide Duke with the revenue requirement to operate the new ESPs while recognizing that the replaced ESPs are still included within Duke's base rates.

7. Settlement Agreement and Supporting Testimony. Duke and the OUCC (the "Settling Parties") entered into a Settlement Agreement, a copy of which is attached and incorporated herein.

Mr. Miller testified that the settlement was the product of negotiations among Duke and the OUCC, conducted on an arms' length basis. The Settlement Agreement provides for approval of Duke's proposed Phase 3 Plan, cost estimate, and ratemaking and accounting proposals, with certain revisions and stipulations. The primary substantive features of the Settlement are: (1) the withdrawal of Duke's request for approval of permanent mercury sorbent traps at Edwardsport; (2) the commitment to notifying the Commission and OUCC within 30 days of making a final decision on the mercury trim control selection at Cayuga Units 1 and 2, and to discussing the results of its calcium bromide testing at Cayuga through the applicable ECR testimony; (3) the commitment to withdraw its request to install ACI at Gibson Unit 5 (as was approved in Phase 2) and to reflect that plan change in its next ECR filing; (4) the Settling Parties' agreement that a hard cost cap on Duke's cost estimate is not appropriate; and (5) the agreement to reduce depreciation expense recovered on the new Gibson Station precipitator investment in Duke's Rider 71 proceeding to reflect the effect of retired original precipitator investment.

Mr. Miller testified that to reflect the cancellation of the ACI project at Gibson Unit 5 and its replacement with calcium bromide for mercury trim control, Duke will list the ACI for Gibson Unit 5 as "cancelled" on the Phase 2 project exhibit in the next ECR filing after a Commission Order in Phase 3 approving calcium bromide for Gibson Unit 5. He stated that Duke has not spent any portion of the estimated costs for the Gibson Unit 5 ACI system, which simplifies the removal of the ACI scope costs completely from the Phase 2 estimate in its ECR exhibit.

Mr. Miller testified that the proposed deferral of the installation of the Cayuga ACI Systems (to provide time for testing of calcium bromide once the SCRs are in service) will also be reflected in the Phase 2 exhibit in the next ECR filing after a Commission Order in Phase 3 approving calcium bromide for Cayuga. However, assuming after testing that calcium bromide is independently successful at Cayuga, reflecting the future cancellation of the approved ACI systems on the Phase 2 exhibit in ECR will be more complex than it will be to reflect the cancellation of the Gibson 5 ACI. He explained that this is due to the Cayuga ACI projects being managed together with the dry sorbent injection and arsenic mitigation systems. As such, there are portions of the costs associated with engineering and construction included in both the ACI and dry sorbent injection system estimates. Mr. Miller testified that if Duke proceeds at Cayuga with just calcium bromide, Duke would not be able to simply remove the Cayuga ACI system line items from its Phase 2 Plan estimate. He stated that by the time this decision is made, the balance of the sorbents scope will be complete and actual costs relative to the combined scope estimates will be known. Mr. Miller testified that should ACI at Cayuga be cancelled, Duke will endeavor to remove the "stand-alone" ACI system costs from the Phase 2 cost estimate in the ECR. Conversely, should Duke proceed with ACI at Cayuga, it should update the estimate for the completion of the ACI scope to better reflect the costs of proceeding with ACI after the other sorbents' installation is completed. Mr. Miller testified that until such decision is made, Duke will add appropriate footnotes to the Phase 2 and future Phase 3 exhibits in the ECR proceeding.

Mr. Miller testified regarding clarifications to the cost estimate for the Gibson Units 3-5 precipitator refurbishments to reflect the joint ownership of Gibson Unit 5. He explained that the winning EPC bid for Gibson Unit 5 represents the entire project cost, but Duke will only be responsible for covering 50.05% of that amount. Therefore, to compare the winning bid amounts to the proposed project estimates, one would need to reduce the Gibson Unit 5 cost by approximately half, which results in more than an 18% difference between the "winning bid" amounts and the cost estimates. Mr. Miller testified that upon discussing these issues, the OUCC has agreed that Duke's cost estimate was reasonable and no cap on construction costs was appropriate.

Mr. Miller testified that the settlement will benefit Duke's retail customers for many years by allowing its generating units to continue operation in compliance with increasingly strict environmental regulations.

Ms. Graft testified that Duke has agreed to withdraw its request for permanent mercury sorbent traps at Edwardsport as part of its Phase 3 Plan. In addition, it has agreed to reduce the depreciation expense to be recovered in Rider 71 associated with the proposed precipitator refurbishment projects at Gibson Station 3-5 by the amount of depreciation expense associated with original ESP investment that is retired as a result of the refurbishment projects. She stated that Duke will calculate the annual depreciation expense reduction by multiplying the amount of retired original ESP investment by the applicable depreciation rates approved in Cause No. 43114 IGCC 4S1. Not all of the original precipitator investment will be retired as a result of the refurbishment projects. Mr. Miller testified that approximately two-thirds of the original investment in the Gibson precipitators will remain in service after the refurbishment. Ms. Graft testified that once the precipitator refurbishment projects are in service and begin to be depreciated in Duke's ECR proceedings, Duke will include a corresponding reduction for depreciation expense associated with the retired original precipitator investment. Ms. Graft testified that the annual retail revenue requirement associated with the reduction in depreciation expenses is estimated at approximately $400,000-$450,000.

Ms. Graft provided the revised rate impact reflecting the terms of the Settlement Agreement. She stated that while the estimated annual revenue requirements decreased slightly, the estimated percentage increases by retail rate group were unchanged. In 2017, the peak year of rate impact in the 2015-2019 time period, the average retail rate impact is still estimated to be a 0.8% increase over total retail revenues for the twelve months ended September 30, 2013.

Mr. Blakley testified that the reduction in the overall cost estimate will slightly lower the revenue requirement for return and overall depreciation related to the Phase 3 Plan and the recognition of the retired ESPs embedded depreciation expense as a credit recognizes the removal of items currently being recovered through rates. Mr. Blakley testified that this credit will be recovered in Duke's Rider 71 and will reduce the overall financial impact to ratepayers. He testified that the reduction in the scope of projects as well as the depreciation expense credit is therefore in the public interest.

8. Commission Discussion and Findings.

A. Approval of Settlement Agreement. Settlements presented to the Commission are not ordinary contracts between private parties. *United States Gypsum, Inc. v. Indiana Gas Co.*, 735 N.E.2d 790, 803 (Ind. 2000). When the Commission approves a settlement, that settlement "loses its status as a strictly private contract and takes on a public interest gloss." *Id.*

(quoting *Citizens Action Coalition of Ind., Inc. v. PSI Energy, Inc.*, 664 N.E.2d 401, 406 (Ind. Ct. App. 1996)). Thus, the Commission "may not accept a settlement merely because the private parties are satisfied; rather [the Commission] must consider whether the public interest will be served by accepting the settlement." *Citizens Action Coalition*, 664 N.E.2d at 406.

Further, any Commission decision, ruling, or order, including the approval of a settlement, must be supported by specific findings of fact and sufficient evidence. *United States Gypsum*, 735 N.E.2d at 795 (citing *Citizens Action Coalition of Ind., Inc. v. Public Service Co. of Ind., Inc.*, 582 N.E.2d 330, 331 (Ind. 1991)). The Commission's own procedural rules require that settlements be supported by probative evidence. 170 IAC 1-1.1-17(d). Therefore, before the Commission can approve the Settlement Agreement, we must determine whether the evidence in this Cause sufficiently supports the conclusions that the Settlement Agreement is reasonable, just, and consistent with the purpose of Indiana Code ch. 8-1-2, and that such agreement serves the public interest.

We find the Settlement Agreement is within the range of the evidence and represents a reasonable resolution of the issues in this cause. Approval also eliminates the risks, uncertainty and consumption of time and resources that would otherwise be required in a fully-litigated proceeding. As discussed above, we give substantial weight to the OUCC's agreement to the Settlement because it is the statutory representative of the consumers.

Based on the evidence of record, we find that the Settlement Agreement between Duke and the OUCC is reasonable, supported by the evidence of record, in the public interest and should be approved without modification or change. Finally, with regard to future citation of the Settlement Agreement, we find the Settlement Agreement and our approval of it should be construed in a manner consistent with our findings in *Richmond Power & Light,* Cause No. 40434 (Ind. Util. Regulatory Comm'n Mar. 19, 1997). The Settlement Agreement shall not constitute an admission or a waiver of any position that any of the Parties may take with respect to any or all of the items and issues resolved therein in any future regulatory or other proceedings, except to the extent necessary to enforce its terms.

B. Approval of Duke's Phase 3 Environmental Compliance Plan. Finding that a project meets public convenience and necessity and approving the estimated costs for that project are separate and distinct components of approving a CPCN. Based on the evidence presented, we find Duke's Phase 3 Environmental Compliance Plan, as revised in settlement testimony, is reasonable and necessary and should be approved.

C. Approval of Estimated Costs. Granting a CPCN depends largely on the economic efficacy of the proposed project; therefore, cost estimates are a significant factor in our decision. It is appropriate to tie a finding of public convenience and necessity to the cost estimate, plus or minus an appropriate range of accuracy, and an underlying analysis provided by the utility in order to determine the viability of the proposed project. Duke requests approval of the cost estimate for its Phase 3 Compliance Plan projects, as set forth in its Confidential Exhibit G-2. The evidence presented demonstrates that Duke's cost estimate for the Phase 3 Projects, as depicted in Confidential Exhibit G-2 is reasonable and necessary. Based on the evidence, we find that the Phase 3 Projects offer substantial potential to cost effectively reduce pollutants. Therefore, we approve

Duke's Phase 3 Projects and their estimated costs, as depicted in Confidential Exhibit G-2 and consistent with the Settlement.

D. <u>Clean Energy Projects</u>. Indiana Code § 8-1-8.8-2(2)(B) defines "clean 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 geological formation known as the Illinois Basin.

We find that Duke's proposed Phase 3 projects meet the applicable definition of clean energy projects. We further find that Duke should be authorized for certain financial incentives, as provided for in Indiana Code § 8-1-8.8-11, in connection with Duke's proposed Phase 3 compliance plan, including: (1) the timely recovery of the financing, construction and operating costs and expenses associated with Duke's Phase 3 Plan via Duke's existing Standard Contract Riders No. 62 and 71; (2) the use of accelerated depreciation in connection with Duke's Phase 3 environmental compliance projects; (3) the authority to defer post-in-service carrying costs as a regulatory asset until the applicable costs are reflected in Duke's rates; (4) the authority to defer depreciation and incremental operation and maintenance costs on an interim basis until the applicable costs are reflected in Duke's rates; and (5) the timely recovery of future plan development, preliminary engineering, testing and pre-construction costs via Rider 62 and/or 71.

E. <u>QPCP Approvals</u>. Duke requests that the Commission approve for use, pursuant to Indiana Code § 8-1-2-6.8 and 170 IAC 4-6-2, Duke's proposed Phase 3 emissions reduction equipment as QPCP. We find that the proposed projects constitute QPCP, as defined in Indiana Code § 8-1-2-6.8, because they represent clean coal technology projects that meet applicable state and federal requirements and are designed to accommodate the burning of coal from the Illinois Basin.

F. <u>Confidentiality Findings</u>. Duke filed a motion for protection of confidential and proprietary information on November 12, 2013, with an Amended Affidavit in support of such motion filed on December 6, 2013. In the motion and supporting affidavit, Duke demonstrated a need for confidential treatment for the Phase 3 compliance plan project costs (including operating and maintenance costs) and proposed project construction schedule. On December 9, 2013, the Presiding Officers made preliminary determinations that such information should be subject to confidential procedures. We find that all such information is confidential pursuant to Ind. Code § 5-14-3-4 and Ind. Code § 24-2-3-2, is exempt from public access and disclosure by Indiana law, and shall be held confidential and protected from public access and disclosure by the Commission

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

1. The Settlement Agreement is in the public interest and is approved.

2. Duke's Phase 3 environmental compliance plan, as revised pursuant to the Settlement Agreement, is approved.

3. Duke's proposed Phase 3 compliance plan constitutes clean energy projects and qualified pollution control property.

4. Duke's request for ongoing review of its proposed clean energy projects is approved. Duke shall update the Commission as part of its semi-annual Rider 62 and 71 filings.

5. The Commission approves Duke's cost estimates as described in this Order and consistent with the terms of the Settlement Agreement.

6. Duke's request for financial incentives in connection with its Phase 3 compliance plan is approved as described above.

7. The information filed by Duke in this Cause pursuant to its Motion for Protective Order is deemed confidential pursuant to Ind. Code § 5-14-3-4 and Ind. Code § 24-2-3-2, is exempt from public access and disclosure by Indiana law, and shall be held confidential and protected from public access and disclosure by the Commission.

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

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

APPROVED: AUG 27 2014

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

Brenda A. Howe

Brenda A. Howe
Secretary to the Commission

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF DUKE ENERGY INDIANA, INC., FOR APPROVAL OF (1) A PHASE 3 PLAN TO ENSURE COMPLIANCE WITH REGULATED AIR EMISSION LIMITS; (2) PETITIONER'S PHASE 3 PLAN PROJECTS AS QUALIFIED POLLUTION CONTROL PROPERTY AND CLEAN ENERGY PROJECTS; (3) CERTAIN FINANCIAL INCENTIVES IN CONNECTION WITH PETITIONER'S PHASE 3 COMPLIANCE PLAN, INCLUDING THE TIMELY RECOVERY OF COSTS INCURRED DURING CONSTRUCTION AND OPERATION OF THE CLEAN ENERGY PROJECTS VIA DUKE ENERGY INDIANA'S RIDER NOS. 62 AND 71, AND THE USE OF ACCELERATED DEPRECIATION; (4) THE AUTHORITY TO DEFER POST-IN-SERVICE CARRYING COSTS AS A REGULATORY ASSET UNTIL THE APPLICABLE COSTS ARE REFLECTED IN PETITIONER'S RATES; (5) THE AUTHORITY TO DEFER DEPRECIATION AND INCREMENTAL OPERATION AND MAINTENANCE EXPENSES ON AN INTERIM BASIS UNTIL THE APPLICABLE COSTS ARE REFLECTED IN PETITIONER'S RATES; AND (6) THE TIMELY RECOVERY OF FUTURE COMPLIANCE PLAN DEVELOPMENT, ENGINEERING, TESTING AND PRE-CONSTRUCTION COSTS	)	**CAUSE NO. 44418**

<u>SETTLEMENT AGREEMENT</u>

Duke Energy Indiana, Inc. ("Duke Energy Indiana") has requested Indiana Utility Regulatory Commission ("Commission") approval of its Phase 3 Environmental Compliance Plan. In support of its Phase 3 Environmental Compliance Plan, Duke Energy Indiana filed its case-in-chief on November 12, 2013. The Indiana Office of Utility Consumer Counselor ("OUCC") filed its case-in-chief on February 14, 2014. The OUCC and Duke Energy Indiana (the "Parties") have reached an agreement with respect to all of the issues before the Commission in this Cause. The Parties therefore stipulate and agree for purposes of resolving all of the issues in this Cause, to the terms and conditions set forth in this Settlement Agreement.

1. **<u>Duke Energy Indiana Phase 3 Environmental Compliance Plan</u>**. The Parties agree that the following projects shall be approved for inclusion in Duke Energy Indiana's Phase 3 Environmental Compliance Plan.

Station	Compliance Plan
Cayuga Station	Units 1-2 – Calcium Bromide Systems PM CEMS
Gibson Station	Units 1-5 – Calcium Bromide Systems Units 3-5 – Precipitator Refurbishments Units 4-5 – Stack Improvements Unit 5 – Relief Duct Dampers PM CEMS

Duke Energy Indiana agrees to withdraw its request for permanent mercury sorbent traps at Edwardsport as part of its Phase 3 Environmental Compliance Plan. Nothing in this Settlement Agreement precludes Duke Energy Indiana from seeking cost recovery for alternate methods of mercury monitoring to comply with U.S. EPA's Mercury Air Toxics Standards ("MATS") or subsequent rules.

2. **Duke Energy Indiana Phase 2 Compliance Plan.** Duke Energy Indiana agrees to notify the Commission and OUCC within thirty (30) days of making a final decision on the mercury trim control selection at Cayuga Units 1 and 2, *i.e.,* whether Duke Energy Indiana will install Activated Carbon Injection ("ACI") or Calcium Bromide Systems, or a combination. Duke Energy Indiana will also discuss the results of its calcium bromide testing at Cayuga through the applicable ECR rider testimony. Duke Energy Indiana commits to withdrawing its request to install ACI at Gibson Unit 5 (as was approved in the Phase 2 Environmental Compliance Plan) and to reflect that plan change in its first ECR filing after a Final Order is issued in this Cause assuming this Settlement Agreement is approved in its entirety without change or condition unacceptable to either party.

3. **Cost Estimate.** The OUCC does not oppose Duke Energy Indiana's cost estimate as provided in Joseph Miller's settlement testimony.

4. **Ratemaking.** Duke Energy Indiana agrees to a reduction to depreciation expense recovered on the new Gibson Station electrostatic precipitator ("ESP") investments in Standard Contract Rider No. 71 – Clean Coal Operating Cost Revenue Adjustment ("Rider 71") to reflect the effect of retired original ESP investment. The Company will calculate the annual depreciation expense reduction by multiplying the amount of retired original Gibson Station ESP investment, once known, by the applicable depreciation rates approved in Cause No. 43114 IGCC 4S1. Not all of the original ESP investment will be retired as a result of the Gibson Station ESP refurbishment projects. The final retirement amount will not be known until the project is completed, and the Company will report on that in the applicable ECR proceeding. Once the Gibson 3-5 ESP refurbishment projects are in service and begin to be depreciated in the Duke Energy Indiana's ECR proceedings, Duke Energy Indiana will also include the corresponding depreciation expense reduction associated with the retired original ESP investment.

The other aspects of Duke Energy Indiana's accounting and ratemaking treatment shall be approved. These items include:

- Timely recovery of costs incurred during construction and operation of the clean energy projects via Duke Energy Indiana's Standard Contract Rider No. 62 – Qualified Pollution Control Property Revenue Adjustment and Rider 71.
- Use of accelerated depreciation as outlined in the testimony of Ms. Christa L. Graft.
- Authority to defer post-in-service carrying costs as a regulatory asset until the applicable costs are reflected in Duke Energy Indiana's Rider 62 or in its next base rate case.
- Authority to defer depreciation and incremental operation and maintenance expenses on an interim basis until the applicable costs are reflected in Duke Energy Indiana's Rider 71 or in its next base rate case.
- Timely recovery of future compliance plan development, engineering, testing, and pre-construction costs.

5. **Miscellaneous.** Unless otherwise noted, all other aspects of Duke Energy Indiana's Phase 3 Environmental Compliance Plan as outlined in IURC Cause No. 44418 shall be approved in their entirety.

6. **Settlement Testimony and Evidentiary Hearing.** Each Party agrees to file settlement testimony that fully supports the terms of this Agreement, and to further support it in the event of any appeal. The Parties agree to waive cross examination of each other's witnesses at the evidentiary hearing and to not object to admissibility of each other's pre-filed testimony.

7. **Proposed Final Order.** The Parties stipulate and agree to the issuance by the Commission of a proposed order (the "Proposed Order") that wholly adopts the terms of this Settlement Agreement. The Parties agree to file a joint proposed order with the Commission after the final evidentiary hearing.

8. **Evidentiary Basis.** The Parties stipulate and agree that the evidentiary material identified above constitute a sufficient evidentiary basis for the issuance of a Final Order by the Commission in accordance with the terms of the Settlement.

9. **Commission Approval.** The concurrence of the Parties with the terms of the Settlement is expressly predicated upon the Commission's approval of the Settlement. If the Commission alters the Settlement in any material way, unless that alteration is unanimously consented to by the Parties, in writing, the Settlement shall be deemed withdrawn. The Parties stipulate that the agreed-upon provisions with respect to the precedential effect of the Settlement and Order are material to the Settlement.

10. **Authorization.** The undersigned have represented and agreed that they are fully authorized to execute this Settlement on behalf of the designated clients who will be bound thereby.

11. **Precedential Status.** The Settlement is a result of compromise derived from unusual and specific facts and representations particular to this Cause. The Parties stipulate that this Settlement should not be construed nor be cited as precedent or deemed an admission by any party in any proceeding except as necessary to enforce its terms before the Commission or any court of competent jurisdiction on these particular issues. This Settlement is solely the result of compromise in the settlement process and, unless otherwise provided herein, is without prejudice to and shall not constitute a waiver of any position that the Parties may take with respect to any or all of the items resolved herein in any future regulatory or other proceeding and shall not be admissible in any subsequent proceeding without regard to whether it has been approved by the Commission. The Parties agree that, other than to enforce the terms of this Settlement, no Party may offer this Settlement or any terms of this Settlement or testimony in support of this Settlement against another party to this proceeding in any subsequent proceeding; and the Parties agree that any such effort is objectionable and constitutes a satisfactory basis for sustaining the objection or motion to strike.

12. Counterparts. This Settlement may be executed in one or more counterparts (or upon separate signature pages bound together into one or more counterparts), all of which taken together shall constitute one agreement.

Dated this 18th day of March, 2014.

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Duke Energy Indiana, Inc.

Douglas F Esamann
President, Duke Energy Indiana, Inc.

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Indiana Office of Utility Consumer Counselor

Lorraine Hitz-Bradley

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