ORIGINAL

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF DUKE ENERGY INDIANA, INC., FOR APPROVAL OF (1) A PHASE 2 COMPLIANCE PLAN REGARDING EMISSIONS REDUCTION REQUIREMENTS; (2) THE USE OF CERTAIN QUALIFIED POLLUTION CONTROL PROPERTY AND CLEAN ENERGY PROJECTS; (3) CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY FOR CLEAN COAL TECHNOLOGY; (4) THE USE OF CONSTRUCTION WORK IN PROGRESS RATEMAKING TREATMENT; (5) CERTAIN FINANCIAL INCENTIVES IN CONNECTION WITH PETITIONER'S COMPLIANCE PLAN, INCLUDING TIMELY RECOVERY OF COSTS INCURRED DURING CONSTRUCTION AND OPERATION OF THE CLEAN COAL TECHNOLOGY PROJECTS VIA DUKE'S RIDER NOS. 62 AND 71, AND THE USE OF ACCELERATED DEPRECIATION; (6) THE AUTHORITY TO DEFER POST-IN-SERVICE CARRYING COSTS, DEPRECIATION COSTS, AND OPERATION AND MAINTENANCE COSTS ON AN INTERIM BASIS UNTIL THE APPLICABLE COSTS ARE REFLECTED IN PETITIONER'S RATES; (7) CONDUCTING ONGOING REVIEWS OF THE IMPLEMENTATION OF PETITIONER'S COMPLIANCE PLAN; (8) THE TIMELY RECOVERY OF EMISSION ALLOWANCE COSTS IN DUKE ENERGY'S RIDER NO. 63; (9) DEFERRAL AND RECOVER THE PHASE 3 PLAN DEVELOPMENT, ENGINEERING AND PRE-CONSTRUCTION COSTS.

CAUSE NO. 44217

APPROVED: APR 03 2013

ORDER OF THE COMMISSION

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

On June 28, 2012, Duke Energy Indiana, Inc. ("Duke" or "Petitioner") filed its Verified Petition and case-in-chief testimony with the Indiana Utility Regulatory Commission ("Commission"), requesting approval of clean energy projects and qualified pollution control property ("QPCP") and the issuance of a certificate of public convenience and necessity ("CPCN") to use clean coal technology to allow Duke to reduce airborne emissions from its existing coal-fired steam electric generating units. Pursuant to notice, given and published as required by law, proof of which was incorporated in the record, the Commission held a Prehearing Conference and Preliminary Hearing at 9:30 a.m. on August 8, 2012 in Hearing Room 224, 101 West Washington Street, Indianapolis, Indiana. On August 15, 2012, the

Commission issued a Prehearing Conference Order setting forth the procedural schedule in this Cause.

The Citizens Action Coalition of Indiana ("CAC"), the Sierra Club, Hoosier Chapter ("Sierra Club"), Valley Watch, Inc., and Save the Valley, Inc. (collectively "Joint Intervenors"), Steel Dynamics, Inc. ("SDI"), and Nucor Steel-Indiana, a division of Nucor Corporation, ("Nucor") filed petitions to intervene in the proceeding. The Presiding Officers granted all petitions to intervene.

On November 29, 2012, the Indiana Office of Utility Consumer Counselor ("OUCC") and Joint Intervenors filed their respective cases-in-chief. On December 18, 2012, Duke filed its rebuttal testimony.

Pursuant to notice given and published as required by law, proof of which was incorporated into the record, the Commission held an Evidentiary Hearing at 9:30 a.m. on January 7, 2013, continuing through January 9, 2013, in Hearing Room 222, 101 West Washington Street, Indianapolis, Indiana. Duke, the OUCC, Nucor, and Joint Intervenors, appeared and participated at the hearing. At the evidentiary hearing, Duke, Joint Intervenors, and the OUCC offered their evidence, which was admitted into the record of this proceeding.

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

**1. Notice and Jurisdiction.** Due, legal, and timely notice of the evidentiary hearing in this Cause was given and published as required by law. Petitioner is a public utility as that term is defined in Ind. Code § 8-1-2-1(a), and is subject to the Commission's jurisdiction under Ind. Code ch. 8-1-2. Ind. Code ch. 8-1-27 gives the Commission authority to review and approve environmental compliance plans. Code ch. 8-1-8.7 gives the Commission authority to issue a CPCN for clean coal technology. Ind. Code ch. 8-1-8.8 and Ind. Code §§ 8-2-1-6.1, 8-1-2-6.7, and 8-1-2-6.8 give the Commission authority to approve certain accounting methods and financial incentives related to the installation and use of clean coal technology and qualified pollution control property. Therefore, the Commission has jurisdiction over Petitioner and the subject matter of this proceeding.

**2. Petitioner'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 renders 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.** Petitioner requests approval of its proposed Phase 2 plan for reducing emissions in light of pending emissions reduction requirements, including the construction and use of various emissions reduction equipment. In addition, Petitioner requests the following: (1) approval for use, pursuant to Ind. Code § 8-1-2-6.8, Ind. Code ch. 8-1-8.8, and 170 IAC 4-6-2, of Petitioner's proposed Phase 2 emissions reduction equipment, as QPCP and clean energy projects; (2) the Commission grant Petitioner a CPCN for the construction and use of clean coal technology, to the extent required by Ind. Code § 8-1-8.7-1; (3) approval of the use of construction work in progress ratemaking treatment; (4) ongoing review of Petitioner's implementation of its compliance plan; (5) pursuant to Ind. Code § 8-1-2-6.8 and Ind. Code ch. 8-1-8.8, assurance of cost recovery of capital investments made pursuant to a Commission-approved compliance plan; (6) timely recovery of the financing, construction, and operating costs associated with Petitioner's Phase 2 plan, as previously authorized by this Commission's Order in Cause Nos. 42622 and 42718, via Petitioner's existing Standard Contract Riders No. 62 and 71; (7) authorization for the use of accelerated (20-year) depreciation in connection with Petitioner's environmental compliance projects; (8) timely recovery of emission allowance costs incurred in connection with compliance with new sulfur dioxide ("$SO_2$") and nitrogen oxide ("$NO_x$") emissions reduction requirements via Petitioner's existing Standard Contract Rider No. 63; (9) timely recovery of Phase 3 plan development, preliminary engineering, testing, and pre-construction costs via Rider 62 and/or 71; and (10) the authority to defer post-in-service carrying costs on an interim basis, until the applicable costs are reflected in Petitioner's rates.

**4. Duke's Proposed Compliance Plan.** Petitioner proposed its Phase 2 environmental compliance plan primarily based on known requirements for complying with the Utility Mercury and Air Toxics Standard ("MATS"). Petitioner revised its original Phase 2 Compliance Plan in rebuttal testimony to defer investment in activated carbon injection ("ACI") systems at its Gibson Station Units 1 through 4 and Gallagher Station Units 2 and 4, pending additional testing and emissions monitoring.

**Petitioner's Revised Phase 2 Compliance Plan:**

| Station | Compliance Plan | Estimated In-Service or Retirement Date |
|---|---|---|
| **Cayuga Station** | **Unit 1** – SCR, DSI, ACI, arsenic mitigation system, mercury re-emission chemical injection system | December 2014 |
| | **Unit 2** – SCR, DSI, ACI, arsenic mitigation system, mercury re-emission chemical injection system | June 2015 |
| **Gibson Station** | **Unit 1** – mercury re-emission chemical injection system | November 2014 |
| | **Unit 2** – mercury re-emission chemical injection system | December 2014 |
| | **Unit 3** – mercury re-emission chemical injection system | December 2014 |
| | **Unit 5** – ACI, mercury re-emission chemical injection system | May 2015 |
| **Wabash River Station** | **Unit 2** – retirement | April 2015 |
| | **Unit 3** – retirement | April 2015 |
| | **Unit 4** – retirement | April 2015 |
| | **Unit 5** – retirement | April 2015 |

5. **Duke's Direct Evidence.**

A. **Existing Emissions Reduction Requirements.** Douglas F. Esamann, President of Duke, Inc., testified that Existing federal and state emission reduction mandates have already required significant $SO_2$ and $NO_x$ reductions. In the 1990s, Duke invested over $500 million in pollution control equipment to reduce $SO_2$ and $NO_x$ emissions under the 1990 Clean Air Act Amendments. Between 2000 and 2005, Duke invested another $569 million in $NO_x$ control equipment to further reduce emissions in compliance with federal and state $NO_x$ State Implementation Plan ("SIP") Call requirements. Since 2005, Duke has invested close to $1.1 billion to comply with the Clean Air Interstate Rule ("CAIR") and Clean Air Mercury ("CAMR") rule and as part of a Consent Decree reached with the U.S. Department of Justice related to New Source Review ("NSR") claims. Mr. Esamann testified that Duke's prior equipment investments are also required to comply with the MATS rule and the Cross State Air Pollution Rule ("CSAPR"). Mr. Esamann testified that since 1990 Duke's emissions of $SO_2$ and $NO_x$ have decreased by over 84% (a 434,544 ton reduction from 515,180 tons emitted in 1990) and over 73% (an 83,861 ton reduction from 115,350 tons emitted in 1990), respectively, despite concurrent increases in customer demand and megawatt hours produced. He explained that the reductions have been achieved through the installation of pollution control equipment, the use of lower-sulfur fuel, and increased fuel diversity in Duke's generation portfolio.

B. **Pending and Anticipated Environmental Rules Driving Petitioner's Compliance Plans.**

1. **MATS.** Joseph A. Miller, Jr., General Manager, Analytical & Investment Engineering, of Duke Energy Business Services LLC, testified that MATS is the main rule driving Duke's compliance plan in this proceeding. J. Michael Geers, an Environmental Health and Safety Manager with Duke Energy Business Services LLC, explained that the U.S. Environmental Protection Agency ("EPA") finalized MATS on February 16, 2012, as a replacement for the vacated CAMR rule. 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. Mr. Geers said that because MATS is a command and control program and does not allow emission allowance trading, facilities will be forced to either retrofit to achieve the standard or shut down to avoid operating out of compliance.

Mr. Geers 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 gigawatt-hour of electricity generated. He stated that in addition to limits on mercury, Petitioner'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 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, Petitioner will also be subject to work practice standards to minimize the emission of organic hazardous air pollutants.

Mr. Geers testified that compliance with the MATS rule is required three years after its effective date, which was April 16, 2012. The EPA has indicated that, for units installing controls, sources could potentially apply for an extension with IDEM.[1] Mr. Geers 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 Phase 2 compliance plan construction is not complete, it is possible that Duke would have to shut down any units that would fail to meet the MATS-imposed emission limits.

Mr. Geers 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 optionality of the MATS rule for complying with the Filterable PM provisions or the non-mercury metals provisions, Petitioner 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 are still being assessed for potential capital and operational impacts.
- A final MATS compliance date of April 16, 2015.

**2.** **CSAPR.** Mr. Geers testified that on August 8, 2011, the EPA published the final rule to replace CAIR, now referred to as CSAPR. CSAPR, which establishes state-level annual $SO_2$ and $NO_x$ 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 pending the Court's resolution of the CSAPR litigation. The Commission notes that the U.S. Court of Appeals for the D.C. Circuit vacated CSAPR on Aug

[1] Duke received a six-month extension of MATS compliance for Cayuga Unit 2, a six-month extension of compliance for Gibson Unit 3, and a one-year extension of compliance for Gibson Unit 5.

21, 2012. *EME Homer City Generation, L.P. v. EPA*, 696 F.3d 7 (D.C. Cir. 2012) (reh'g denied, 2013 U.S. App. LEXIS 1624 (D.C. Cir. Jan. 24, 2013).

**3. Proposed 316(b) Cooling Water Intake Structures Rule ("316(b)").** On April 20, 2011, the EPA published in the Federal Register its proposed cooling water intake structures rule. Mr. Miller testified that the EPA's preferred approach would 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, and that utilize at least 25% of the water withdrawn for cooling purposes. Mr. Miller stated that the rule covers aquatic mortality caused by impingement of organisms against cooling water intake screens, and due to entrainment of organisms in the water through the cooling systems.

**4. Proposed Coal Combustion Residuals ("CCR") Rule.** Mr. Miller testified that CCRs primarily include fly ash, bottom ash, and flue gas desulfurization ("FGD") byproducts (typically calcium sulfate (gypsum) or calcium sulfite) that are destined for disposal. Mr. Miller 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. Miller 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. Miller testified that ultimate compliance is generally expected in the 2017 to 2021 timeframe.

**5. Steam Electric Effluent Guidelines.** Mr. Miller testified that these guidelines govern the quality of water discharged from generating facilities. On April 2, 2012, the U.S. Court of Appeals for the D.C. Circuit entered a consent decree between the EPA and intervenors that requires the EPA to issue a proposed rule by November 20, 2012, and a final rule by April 28, 2014. Mr. Miller testified that after the final rulemaking, new effluent guideline requirements will be included in a station's NPDES permit renewals, although states have the option to re-open permits and include the requirements immediately upon the finalization of the rule.

**6. National Ambient Air Quality Standards ("NAAQS").** Mr. Geers testified that on June 14, 2012, the EPA proposed lowering 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 retaining the current 24-hour standard at 35 $\mu g/m^3$. The EPA was to finalize the new standard by December 14, 2012, and make final area designations for the new standard by December 2014. Mr. Geers testified that once designations are final, states with non-attainment areas will have three years to develop a State Implementation Plan outlining how they will reduce pollution to meet the standard by 2020.

Mr. Geers testified that the current 8-hour ozone standard is 75 parts per billion ("ppb"). Mr. Geers 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 2014. Compliance with the next standard would likely be required in the 2019-2020 timeframe.

Mr. Geers testified that effective August 23, 2010, the 1-hour $SO_2$ NAAQS requirement is 75 ppb. EPA has until June 2013 to finalize area designations, with compliance by late 2017 or early 2018. Mr. Geers testified that EPA has said it will designate areas with monitored air quality above the standard as non-attainment, and designate all other areas as unclassifiable. What is not clear at this time is how, or if at all, EPA will continue to require states to perform source-specific modeling of major $SO_2$ emission sources in unclassifiable areas. Mr. Geers testified that if EPA finalizes the classification of non-attainment, then all of Duke's coal-fired facilities would be potential targets for additional $SO_2$ reduction requirements. If the modeling is not required for unclassifiable areas, then there may not be compliance requirements linked to the late 2017 or early 2018 compliance schedule.

**C. Petitioner's Compliance Planning Process.** Mr. Miller testified that Petitioner uses an integrated, multi-step compliance planning process. The process begins with the development of near-term and long-term assumptions that govern the overall requirements for compliance. In modeling the assumed requirements for compliance, Mr. Miller testified that Petitioner used the following:

**1. MATS.** Duke considered the potential of FGDs, selective catalytic reduction ("SCR"), electrostatic precipitators, baghouses, dry sorbent injection ("DSI") and activated carbon injection ("ACI") systems, $SO_3$ mitigation systems of multiple types, fuel switching, as well as other types of chemical additives for mercury control. Mr. Miller testified that some combination of these controls on each unit is required to achieve compliance.

**2. CSAPR.** Due to the implementation of Duke's Phase 1 plan, which was designed for CAIR compliance, Mr. Miller testified that Petitioner did not identify any additional environmental control projects specifically needed for CSAPR compliance.

**3. 316(b).** Mr. Miller testified that Petitioner assumed that the EPA generally finalizes its proposed preferred approach as detailed above. He stated that costs associated with the impingement provisions of the rule include various aquatic, technical, and engineering studies that are required to be performed. Petitioner also included capital costs for intake structure upgrades, such as mesh screen upgrades and installation of fish return systems. Operations and maintenance costs for impingement mortality monitoring were also included by Petitioner. Mr. Miller testified that Petitioner did not include in its analysis additional specific costs for implementing the entrainment provisions of the rule.

**4. CCR.** Mr. Miller testified that Petitioner assumed that the EPA generally finalizes a Subtitle D non-hazardous designation rule, requiring conversion to full dry ash handling (both fly ash and bottom ash); closure in place of active and inactive wet ash ponds with a synthetic cap; installation of balance-of-plant wastewater treatment systems; and otherwise higher operations and maintenance costs for waste handling and storage due to the more stringent requirements. Mr. Miller testified that Petitioner assumed closure of wet ash ponds must begin by July of 2018, with the dry ash conversions and wastewater treatment systems installed in the 2017 to 2018 timeframe.

5. **Steam electric effluent guidelines.** Mr. Miller testified that Petitioner assumed a finalized guideline requiring the application of FGD wastewater treatment technology, specifically bio-reactors, and prohibiting the discharge of fly ash touched water – which would require conversion to dry ash collection. He stated that to be conservative, Petitioner assumed that Indiana would re-open all National Pollutant Discharge Elimination System ("NPDES") permits and incorporate the new requirements. Mr. Miller testified that Petitioner modeled compliance by 2017.

6. **NAAQS.** Petitioner assumed a new lower ozone standard in 2014, with compliance by 2020, which would require Indiana to issue an implementation plan imposing further reductions in $NO_x$ emissions. Mr. Miller testified that while not assuming any particular numerical limit, Petitioner assumed this would require the installation of SCRs at Cayuga Station, selective non-catalytic reduction equipment at Gallagher Station and Wabash River Station, and SCR upgrades at Gibson Station.

Following development of the assumptions, Mr. Miller testified that Duke then worked with outside vendors that forecast key market commodity parameters, such as fuel prices and energy prices, to develop the Duke Energy Fundamental Forecast. Mr. Miller testified that Duke uses that market information, along with cost and performance characteristics for environmental control options and new capacity resource options, in internally-developed screening models to narrow down a large number of alternatives to the most viable and economic alternatives. He stated that those best alternatives are then analyzed in more detail through Duke's Integrated Resource Planning models. Mr. Miller testified that in this step, the units' environmental control alternatives are assessed against retirement and replacement options, while still meeting reserve margin constraints. Lastly, through multiple sensitivity scenarios, the top selected alternatives are tested for robustness.

**D. Fuel Price Forecasts Utilized in the Development of the Duke Fundamental Forecast.** Robert W. Fleck, Vice President of Gas and Power Consulting, Americas for Wood Mackenzie, Inc., testified that Wood Mackenzie, a global energy research and consulting company specializing in gas, coal, and power forecasts, has worked with Duke Energy Corporation for the past three years assisting in the development of the annual Duke Fundamental Forecast. He explained that the Duke Fundamental Forecast is used throughout the organization, including in Indiana, in preparing internal budgeting, capital planning, and regulatory filings. He testified that the use of this forecast provides the entire Duke Energy organization with a consistent set of planning assumptions for whatever task they are charged with undertaking.

Mr. Fleck testified that each Wood Mackenzie forecast of energy prices is prepared using sophisticated tools to integrate all energy markets globally and those unique to the region and fuel being forecast. The economics team establishes key economic variables such as GDP for each country as well as global average GDP, country inflation rates, and currency exchange rates. Global oil, natural gas, LNG, power, and coal forecasts are developed using a fundamental-based, bottom up approach that looks at nearly every supply and demand source for each commodity around the globe. Supply potential and production costs are evaluated by regional upstream teams for each commodity, by country and region. Supply potential and costs are evaluated on a play by play (mine by mine, plant by plant) basis that cover all the key resources within a region (such as North America). Mr. Fleck testified that forecasts of demand for each commodity are similarly developed by regional teams who forecast using historical trends for each customer class and incorporate the GDP forecast, competing fuels, imports and exports, transportation/transmission/shipping costs, capacity, and any general industry changes such as carbon legislation or increased use of renewable or conservation. Each commodity market is then balanced between supply and demand to develop an initial price forecast for each commodity within each region using sophisticated linear forecasting models and a rolling 15-year normal weather pattern. Mr. Fleck testified that the results are then put into a feedback loop for iteration among commodities and regions until all regional and global forecasts reach convergence among supply, demand, and price. The forecasting cycle takes several months and is initiated immediately after issuance of the then current forecast. Mr. Fleck testified that Wood Mackenzie's long term forecasts are updated every six months and published to its client subscribers to incorporate the ever-changing energy markets environment.

Mr. Fleck testified that natural gas prices are driven by the fundamentals of supply and demand. He stated that gas prices in the forecast are essentially being set by the cost of the "last Mcf" produced. Wood Mackenzie has developed cost curves for each of the gas producing formations in North America, as well as regions that are currently too costly to be produced or further developed at this time. Coal prices are also determined based on the fundamentals of supply and demand. He explained that supply and demand fundamentals for coal are entered into Wood Mackenzie's proprietary PRISM model including detailed supply curves for 71 bituminous, 11 sub-bituminous, 15 lignite, and 4 imported coal types plus petcoke and coal refuse. The coal supply curves are based on mine-by-mine analysis of 1,400 plus U.S. and Latin American mining operations including estimates of mining cost, production capacity, coal quality and reserves.

Mr. Fleck testified that power prices are driven and determined using the EPIS Aurora XMP® ("Aurora") model, a chronological, unit-commitment dispatch model. Aurora performs a simulation of hourly commitment and merit-order economic dispatch of incremental supply sources required to meet hourly power demand under certain system constraints, such as transmission import/export capability and power plant operational limitations. He stated that ultimately, the hourly wholesale power prices are set by the marginal resources required to meet the final megawatt of demand. Mr. Fleck testified that the forecast for delivered coal and natural gas prices has rapidly become the single biggest driver for wholesale power prices, outside of the supply/demand balance. He testified that beyond 2020, the forecast incorporates a federal carbon pricing regime which has a direct impact on dispatch economics and the marginal cost of production. By imposing an incremental cost of carbon emissions, the dispatch cost of the marginal resource, whether coal or natural gas, will increase accordingly based on the underlying cost curves.

Mr. Fleck testified that the Duke Fundamental Forecast is based on the Wood Mackenzie Long Term View, modified to incorporate the following specific assumptions provided by Duke

Energy: (1) the October 6, 2011 revisions to CSAPR; (2) an additional year to comply with MATS is granted only if a plant intends to install controls. If not, the unit is retired in 2015; (3) compliance with Coal Combustion Residuals will occur by 2018; (4) compliance with 316(b) for Best Technology Available to be employed for once-through cooling, which included a one-time capital charge of $10/kW (2011 real) for units without closed loop cooling, which only impacted retirement decisions; (5) $CO_2$ tax set at $15/metric ton (2009 real dollars) escalated at 6% real beginning in 2020; (6) delayed and reduced entry of generic nuclear generation facilities in the long term, resulting in a 4 GW lower projection of nuclear capacity across the United States than the Wood Mackenzie case; (7) an increased amount of solar generation in North Carolina based on trends already documented in the pipeline specific to the North Carolina tax credit; and (8) a flat 2.3% general inflation rate, while Wood Mackenzie assumes higher inflation in the near term and lower inflation in the longer term. However, these inflation rate differences only impact the translation to nominal dollars after the forecast has been produced because Wood Mackenzie's models assume REAL pricing in 2011 dollars.

**E. <u>Robustness of Phase 2 Compliance Plan</u>.** Robert A. McMurry, Director, Integrated Resource Planning, for Duke Energy Business Services LLC testified that Duke used the latest load forecast, energy efficiency and demand response projections, fundamental coal and gas prices, and allowance cost projections, to evaluate the production and capital costs associated with installation of the controls versus retirement of the units and replacement with natural gas-fired generation over a range of sensitivities. He explained that Petitioner performed these analyses to assure that the Phase 2 environmental projects proposed are in the best interests of customers, while also taking into account potential costs associated with Duke's preliminary Phase 3 environmental projects.

Mr. McMurry testified that Duke included the following sensitivities in evaluating the proposed Phase 2 projects: (1) a 20% increase and a 5% decrease of the cost for major capital components; (2) a high fuel cost of gas prices +35% and coal prices +20%; (3) a low fuel cost of gas prices -20% and coal prices -40%; (4) a no $CO_2$ sensitivity was performed as a proxy for a future with carbon legislation delayed beyond 2020 or implemented in another way that does not explicitly incorporate a price on carbon emissions to gauge carbon's impact on the Present Value of Revenue Requirement ("PVRR") of continuing to operate units with coal versus retirement and replacement with natural gas; (5) the high and low load forecast sensitivities (which were limited to Cayuga Units 1 and 2 and Gibson Unit 5 to limit the number of expansion plans); and (6) a 30% increase and a 5% decrease of the cost of new combined cycle units. Mr. McMurry testified that Duke also considered renewable energy resources and purchased power.

Mr. McMurry testified that the modeling shows that installation of Phase 2 and currently expected Phase 3 controls on Cayuga Units 1 and 2 is cost effective by 0.45% versus retirement and replacement with combined cycle generation on a total system PVRR basis. The installation of Phase 2 and currently expected Phase 3 environmental controls on Cayuga is also the most cost effective option versus retirement in all of the sensitivities, ranging from 0.21% in the High Environmental Capital cost scenario to 2.64% when excluding the impacts of $CO_2$. Mr. McMurry testified that the Gibson modeling shows that installation of Phase 2 (which included ACI systems on Gibson Units 1 through 4, later removed by Duke from the Phase 2 Plan) and preliminary Phase 3 controls is more cost effective than retirement and replacement with combined cycle generation by more than 0.73% based on total system PVRR. Mr. McMurry testified that the retirement of Wabash River 2-5 and replacement with combustion turbine generation is more cost effective by 1.23% than the installation of environmental controls.

F. **Long-Term Load Forecasting and Impact of Energy Efficiency Programs on Load Forecast.** Jose I. Merino, Director of Load Forecasting for Duke Energy Business Services LLC, 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 2012 and 2017 for MWH sales and no growth for 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, as described in Duke's July 1, 2012 compliance filing in Cause No. 42693-S1, 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 ("SUFG") forecast for the entire state of Indiana for the residential segment; however, Duke shows slightly lower growth rates for the commercial and industrial sectors. 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 Integrated Resource Planning Group.

Mr. Merino testified that Duke developed high and low scenarios for energy sales and peak demand projections based on the probability distribution of the base case forecast. He testified that the energy sales and peak demand sensitivities were developed in the same manner as the base case projection, but this time the forecasts were stressed by 1.96 standard deviations to show a 95% confidence interval. The results indicate that the peak forecast can vary by approximately 7% from the base case with a 95% probability. For example, the base peak demand forecast for the year 2020 is 6,592 MW and the range of possible outcomes has a high value of 7,094 MW and a low value of 6,093 MW. Mr. Merino testified that, in his opinion, Duke's load forecast is reasonable and adequately considers EE impacts.

G. **Phase 2 Cost Estimate**. David A. Renner, Vice President of Generation Engineering for Regulated Generation of Duke Energy Business Services LLC, testified that Duke compiled its cost estimate through the use of quantity-based estimates derived by Sargent & Lundy, its engineering consultant on the Phase 2 projects. Duke's revised Phase 2 plan, which defers investment in ACI systems at Gibson Station Units 1 through 4 and Gallagher Station Units 2 and 4, will require approximately $395 million in capital (without allowance for funds used during construction ("AFUDC"). He testified that Petitioner used conservative assumptions for the escalation of certain materials and labor over the time period of its proposed Phase 2 projects, based on its experience with the labor pool in Indiana. The estimate also contains assumptions for the yet-to-be-selected construction contractor's anticipated general and administrative expenses, likely fee, and the potential risk premiums associated with a lump sum, guaranteed schedule construction contract, which is what Duke sought for the construction of the SCR retrofits, ACI, and DSI systems at Cayuga Station. He testified that Duke also included a conservative contingency amount, designed to cover the risks associated with the project at this stage of construction – where the main contracts have not yet been bid.

Mr. Renner testified that as a further step, Duke engaged an independent engineering consultant to perform an assessment of the rates, productivity factors, and cost categories contained in the estimate. Duke also engaged Burns & McDonnell to provide a third party review of the current capital cost estimate for the Cayuga retrofit projects. Mr. Renner testified that Petitioner's estimate should be considered a Class 2 estimate, by the standards set forth by the Association for the Advancement of Cost Engineering ("AACE") Recommended Practice 18R-97. He explained the characteristics of a Class 2 estimate as: (1) detailed design is between 30% and 70% complete; (2) detailed unit costs are applied and a proportion of take-off quantities are still estimated; and (3) the expected accuracy range is between +5% and +20% on the high end and between -5% and -15% on the low end. Mr. Renner testified that 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 design is finalized, bids come in and contracts are signed. He also stated that Duke has successfully completed past projects of similar type which adds further credence to the reasonableness of the estimate.

Mr. Gary D. Mouton, lead project estimator in the construction design build group of Burns & McDonnell Engineering Company, Inc. testified that the estimate met the requirements of an AACE Class 2 estimate. He also testified that the estimate provided by S&L was complete and reasonable, and Duke's cost estimate for the Cayuga SCR retrofit projects was reasonable for this stage of design and construction.

Mr. Renner testified that Duke will utilize the services of an Owner's Engineer (a firm that works directly to produce the design for the owner, as opposed to an engineering firm that is subcontracted by a larger constructor to produce a design under a consortium or EPC approach) to perform the design and design coordination functions and deliver the drawings, specifications and standards necessary to procure, construct, and operate the projects. Duke will utilize firm price contracts to the most reasonable extent possible to procure the major supply components of the projects, while relying on industry indices for some portions that may be subject to commodity market escalation. He testified that Duke intends to award a General Work type of contract to a single firm for the construction portion of the projects, which will likely be a firm price contract, but will also examine the use of incentives or risk-sharing to drive aspects of safety, productivity, and cost savings. Mr. Renner testified that Duke proposes to provide the Commission and other stakeholders ongoing review project reports on a semi-annual basis through Duke's Environmental Cost Recovery ("ECR") filings.

**H. <u>Proposed Cost Recovery and Rate Impacts</u>.** Kent K. Freeman, Rate Strategy and Projects Director, Rates – Indiana for Duke, testified that Duke is requesting approval to include incremental depreciation and operations and maintenance ("O&M") expenses for the projects through Rider 71. Petitioner also plans to include certain Phase 2 and Phase 3 plan development, engineering, and pre-construction costs that have been or will be incurred and cannot be capitalized to the environmental projects to be included in Rider 62 and to amortize such costs over a three-year period. Duke is also requesting approval to defer and recover the Phase 3 plan development, preliminary engineering, testing and pre-construction costs via Rider 71. Mr. Freeman testified that until the amounts currently included in Rider 71 are moved to base rates in a retail base rate case proceeding, recovery of these costs will remain in Rider 71, consistent with how Rider 62 is treated. Petitioner is also proposing to commence construction work-in-progress ("CWIP") ratemaking treatment on the environmental projects, via Duke's Rider 62, upon Commission approval of the project as QPCP. Petitioner is also requesting authority from the Commission to accrue post-in-service carrying costs at rates equal to Duke's AFUDC rates on the jurisdictional portion of the capital expenditures for the plan once they are placed in-service until the costs can be included in retail rates. Mr. Freeman testified that the estimated AFUDC on the environmental projects, without consideration of CWIP, would be approximately $33 million. Mr. Freeman testified that Duke plans to account for the retirement of Wabash River Units 2-5 as normal retirements pursuant to U.S. generally accepted accounting principles ("GAAP"). This results in the net book value of these units being redistributed to other similar assets included in plant-in-service and recovered in future retail rate cases.

Duke has forecasted the rate impact of both the capital and increased O&M costs associated with the environmental projects. Mr. Freeman testified that the rate impact will vary based on the following variables: (1) timing of the environmental projects; (2) the actual AFUDC and the actual AFUDC rates applied to the environmental projects; (3) the final environmental projects' costs; (4) the actual O&M costs; and (5) the actual capital structure, cost of capital rates, and revenue conversion factors in effect for the rider filings. Mr. Freeman testified that in 2017, the highest rate impact in the 2013-2017 timeframe, the average retail rate impact is estimated to be 6.3% when compared to total retail revenues for the twelve months ended December 31, 2011. He stated that this percentage could be lower, by as much as 2%, based on the actual variable O&M experienced.

Mr. Freeman testified that Petitioner is proposing a 20-year recovery period (or shorter if the normal life is shorter) for the depreciation expense, and a negative 10% net salvage factor for its environmental projects. The resulting depreciation rate, including adjustment for negative net salvage, is 5.50%. He testified that Duke is also requesting that the Commission approve recovery of any emission allowances associated with CSAPR, or its replacement, in Rider 63.

**6. <u>Disputed Issues</u>.**

**A. <u>ACI Systems at Gallagher and Gibson</u>.**

**1. <u>OUCC's Evidence</u>.** Based on Duke's historical emissions, Cynthia Armstrong, Utility Analyst in the OUCC's Electric Division, stated that the Cayuga Units 1 and 2 SCRs and $SO_3$ mitigation systems and the Gibson Units 1-4 ACI systems were unnecessary to comply with MATS and other existing or pending air regulations at this time. Ms. Armstrong noted that the Gallagher Units 2 and 4 ACI systems, the Gibson Unit 5 ACI Systems, and the Gibson mercury re-emission chemical systems also appeared to be unnecessary, but the OUCC did not oppose approval of these systems in order to enhance the operational flexibility of these generating units.

Ms. Armstrong testified that the historical annual mercury emissions from the Gallagher Generating Station show that the remaining Gallagher units are currently meeting mercury MATS limits with no additional controls. However, she noted that Duke is concerned that combustion tuning required by the Organic Hazardous Air Pollutants Work Practice Standard ("WPS") in the MATS rule may reduce the amount of unburned carbon in the ash on Gallagher Units 2 and 4, which could reduce both units' ability to capture mercury in the baghouses. She stated that although Duke does not have conclusive evidence that the execution of the MATS WPS for organics will impact the mercury emissions on Gallagher Units 2 and 4, it has provided evidence to the OUCC which suggests that lowering the loss on ignition rates on Gallagher Units 2 and 4 could begin to interfere with these units ability to meet the mercury MATS limits. Therefore, she reasoned that the OUCC would not oppose the approval of the ACI on Gallagher Units 2 and 4 because ACI provides future operational flexibility for those units in the event that the organics WPS does negatively impact Gallagher's mercury emissions, and she concluded the capital costs are low enough to make the expenditure worthwhile.

Ms. Armstrong also testified that the OUCC supported installing mercury re-emissions chemical systems on Gibson Units 1-5 because the test results of the mercury re-emissions chemicals on the Gibson units showed that Gibson is experiencing mercury re-emission issues across its units' FGDs at a level significant enough to impact unit mercury emission rates. She stated that using mercury re-emissions equipment could improve the operational flexibility of these units. She stated that the capital costs of the mercury re-emissions equipment is low and makes the investment to improve the operational flexibility of Gibson Units 1-5 worthwhile.

Ms. Armstrong stated that the OUCC also supports the installation of ACI on Gibson Unit 5 because Gibson Unit 5 has the highest mercury emissions of the five units. She explained that if Duke were to use facility-wide averaging for Gibson, Unit 5's emissions have the potential to throw the entire facility out of compliance with MATS, especially if Duke dispatches Gibson 5 more often than in recent history. She reasoned that ACI on Unit 5 is necessary to provide an ample margin between mercury emissions at the MATS mercury limit for Unit 5 and the entire Gibson facility.

However, Ms. Armstong asserted that there is not much evidence that the other Gibson Units need ACI after mercury re-emissions are minimized. She stated that the testing results on Gibson Units 1-4 show that only one control technology is needed for Gibson Units 1-3, and that mercury re-emissions additives would provide the most incremental removal. She recommended that Duke continue following the issue of mercury re-emissions on Gibson Units 1-5 and report back to the Commission, the OUCC, and other interested parties so that a decision regarding the potential need for ACI on Gibson Units 1-4 can be discussed in the future if it is needed.

2. **Duke's Rebuttal Evidence.** Mr. Miller testified that Petitioner was willing to defer investment in ACI systems at its Gibson Station Units 1 through 4 and Gallagher Station Units 2 and 4 pending additional testing and mercury emissions monitoring. Mr. Miller testified that Petitioner will test alternative compliance options and gather monitor data on mercury emissions at Gibson Units 1-4, and perform additional testing on the impact of the MATS organics work practice standards at Gallagher Station before proceeding with its

request to invest in additional controls on these units. As these projects have been withdrawn by Petitioner, they are no longer under consideration by the Commission.

### B. Modeling Errors and Assumptions.

1. **Joint Intervenors' Evidence.** Joint Intervenors filed the testimony of Dr. Frank Ackerman, Senior Economist at Synapse Energy Economics, Inc. ("Synapse"), and Rachel Wilson, Associate with Synapse, alleging a number of deficiencies with the modeling assumptions and economic analysis upon which Duke's proposal is based. Joint Intervenors questioned Duke's base case assumptions about energy efficiency and demand response, price forecasts for carbon emissions, and the price of coal versus natural gas. Joint Intervenors also identified alleged modeling errors in Duke's analysis of the proposed projects at Gallagher Units 2 and 4 that they believe resulted in Duke over-estimating the benefits of retrofitting those units instead of retiring them by nearly $100 million per unit. Joint Intervenors presented their own modeling, which they allege show that using reasonable assumptions regarding demand side management potential and a mid-carbon price, the projected benefits of the Cayuga retrofits would have been negative by hundreds of millions of dollars and the projected benefits of the Gallagher retrofits would have been reduced to near or below zero.

Dr. Ackerman testified that Duke did not run sensitivity analyses for each of these parameters to test the robustness of Duke's Phase 2 plan under a reasonable range of possible futures, but instead only tested a limited range of scenarios that were unreasonably skewed in favor of the Company's proposal. Similarly, Joint Intervenors questioned Duke's failure to optimize its low load growth sensitivity analysis of the Cayuga units' retirement to only retire as much capacity as needed to meet the lower load in that scenario. Joint Intervenors also raised questions about the transparency and accuracy of Duke's modeling and about whether Duke adequately accounted for all future environmental compliance costs and risks, such as the risk that the anticipated Phase 3 projects will be more expensive than Duke anticipates or the risk that Cayuga's Electrostatic Precipitators will need to be upgraded.

In addition, Ms. Wilson noted the possibility that construction of the Phase 2 projects at Cayuga will trigger additional Clean Air Act New Source Review requirements by causing an increase in Cayuga's greenhouse gas emissions of more than 75,000 tons of $CO_2$ equivalent per year. Ms. Wilson said that Duke's demand growth explanation for this $CO_2$ equivalent emissions increase is difficult to understand in light of Duke's weak growth forecast. Ms. Wilson's claimed that her modeling runs questioned whether load growth in fact led to a sustained increase in the energy output of the Cayuga units or to the increase in $CO_2$ equivalent emissions. Instead, Ms. Wilson believes the use of Trona as a sorbent in DSI systems and the increased energy use of the SCR, DSI, and ACI systems proposed for Cayuga could lead to significant increases in $CO_2$ emissions.

Joint Intervenors also filed the testimony of Peter Lanzalotta, Principal with Lanzalotta & Assoc. LLC, who testified that, with the exception of Wabash River Units 2, 3, and 5, the Company has not studied the effect of any other coal-fired generating unit retirements on electric transmission system reliability and has not determined whether such retirements would cause violations of required transmission reliability planning levels. Mr. Lanzalotta emphasized the importance of requiring that any claims by the Company of purported transmission reliability impacts of coal unit retirements be substantiated through an open and transparent review process.

2. **Duke's Rebuttal Evidence.** Mr. McMurry acknowledged and corrected three inadvertent modeling errors regarding the Gallagher Units 2 and 4 analyses. Mr. McMurry submitted corrected Exhibits F-19 and F-20 with his rebuttal testimony. Those exhibits show that controlling Gallagher Units 2 and 4 continues to be the preferred option over retirement and replacement with natural gas. However, as explained above, Petitioner is deferring any investment in Gallagher Units 2 and 4 until additional testing is performed.

Mr. McMurry testified that, in his opinion, the Company used the appropriate range of alternative sensitivities in its modeling for the Phase 2 projects. He explained that it was not necessary to run all of the cases through the low-load forecast scenario (as it did at Cayuga and one unit at Gibson) because Duke was able to make informed judgments based on the other cases that were run. However, to address Dr. Ackerman's concern, Mr. McMurry testified that an additional analysis of the production cost of Gallagher Unit 2 versus retirement and replacement with natural gas generation in a low-load portfolio was compared to the base case analysis. Mr. McMurry testified that this sensitivity demonstrated that the production cost difference between the low-load and the base case was approximately $1 million PVRR and did not have a material impact on the analysis.

Mr. McMurry responded to Dr. Ackerman's claim that the Company biased the analyses against retirement because it should have included less replacement capacity in the retirement cases in the low-load scenario. He disagreed with Dr. Ackerman, stating that the purpose was to determine how the decision would look over the next 20 years if Petitioner proceeded with retrofitting the units but the load level ultimately turned out to be much lower. The Company also ran a high-load sensitivity case with the same purpose in mind. That does not, however, change the Company's view that the base case load forecast is the expected case.

In response to Mr. Lanzalotta's criticism that Duke failed to study whether the retirement of any of its coal-fired units (other than Wabash River Units 2, 3, and 5) would present transmission reliability planning violations, Mr. McMurry testified that as Petitioner had only decided to retire the Wabash Units, the analyses did not include any additional costs for transmission system improvements in the retirement scenarios for Cayuga, Gibson, and Gallagher. The only transmission costs included were in relation to the interconnection of replacement capacity. Mr. McMurry testified that, as a result, the retirement scenario was modeled at a lower cost and, thus, was more conservative than would be the case if MISO determined that there would be additional transmission improvements necessary in order for a unit to be retired. He stated that the Company's analyses showed that retrofits at Cayuga, Gibson, and Gallagher were more cost effective than retirement, using a potentially conservatively low cost for the retirement scenario.

### C. $CO_2$ Price Forecast.

1. **Joint Intervenors' Evidence.** Dr. Ackerman testified that although the United States does not currently place a price on CO2 emissions, many thoughtful observers, including Duke Energy CEO Jim Rogers, anticipate that it will do so in the not-too-distant future. Dr. Ackerman said that the Company assumed a carbon price in its base case but does not provide any support for the specific levels or timing assumed other than to express a belief that if or when Congress does act, it will do so cautiously with a citation to two federal

government reports, both released in 2009. Dr. Ackerman noted that the Company only compared a relatively low price in its base case to a sensitivity that assumes no price at all. Duke did not run any sensitivities that assumed a higher carbon price than the low base case projection.

Dr. Ackerman pointed out, however, that there are many available forecasts of carbon prices that Duke could have considered. Dr. Ackerman presented the 2012 carbon price forecast issued by Synapse. Synapse developed three different carbon price scenarios based on a thorough analysis that evaluated more than forty different sources of information, including projections from other utilities, the U.S. Energy Information Administration, the EPA, the U.S. Interagency Working Group, and McKinsey and Company. The Synapse analysis also considered the impact on $CO_2$ prices of other possible regulatory measures, such as a federal renewable portfolio standard that could simultaneously help to achieve the emission-reduction goals of cap-and-trade. After evaluating all of these sources, Synapse developed three carbon price projections based on three different sets of assumptions regarding the stringency of the likely carbon legislation, the level of emission reductions to be achieved, and the development of technologies and alternatives for reducing carbon emissions. Using those assumptions and sources, Synapse projected a low-carbon price scenario starting at $15 per ton in 2020 and increasing to $35 per ton in 2040; a mid-carbon price scenario starting at $20 in 2020 and increasing to $65 in 2040; and a high-carbon price scenario starting at $30 in 2020 and increasing to $90 in 2040. Finally, Synapse compared its low-, mid-, and high-carbon price projections to the low, mid, and high projections of approximately twenty utilities throughout the country and found its projections to be in the middle of the range of the projections from those utilities.

Ms. Wilson testified that using Synapse's mid-case carbon price while holding all of Duke's other assumptions constant changes the economics of the retrofit of Cayuga Unit 1 from a benefit to a cost to ratepayers. Ms. Wilson said that the same is true for Cayuga Unit 2. Both Dr. Ackerman and Ms. Wilson testified that the Company needs to consider both mid- and high-carbon pricing regimes in its analysis.

**2. <u>Duke's Rebuttal Evidence</u>.** With respect to Joint Intervenors' $CO_2$ data, Mr. Geers observed the following: (1) it is a limited comparison to twenty electric utilities, seven of whom are shown to have price curves just slightly below or slightly above Duke's base case $CO_2$ price curve; (2) twenty of the price curves presented in Ms. Wilson's testimony represent data from a small percentage of the total number of electric utilities in the country; and (3) all but three of the curve vintages provided are of 2009, 2010, or 2011 vintage, which questions whether they are the same price curves the utilities are using today. Mr. Geers testified that after climate change legislation failed in 2009, and the makeup of Congress changed in 2010, Duke reassessed its $CO_2$ prices, lowering them and pushing the start date out in time based on what it saw then and still sees as the new political reality regarding the prospects for and challenges to passage of federal climate change legislation. Mr. Geers testified that if any of the utilities for which Dr. Ackerman presented curves have done the same, it would make the comparison Dr. Ackerman presented outdated and misleading. Mr. Geers testified that even if Dr. Ackerman had presented current $CO_2$ price curves for every utility in the country and the majority of those curves were above Duke's current base case price curve, that would not, by itself, be a compelling reason for Duke to adjust its current view.

Mr. Geers testified that Duke's current assumption regarding the timing of federal climate change legislation for the purpose of reflecting that potential risk in its analyses is that federal climate change legislation could be enacted in 2017 that would set a price on $CO_2$ emissions beginning in 2020. Mr. Fleck testified that Synapse has justified its $CO_2$ pricing using faulty processes that rely on old, outdated, and for the most part, now incorrect forecasts. Their forecast does not reasonably reflect today's reality. He testified that the Synapse forecast starts several years earlier and at a higher level than what Wood Mackenzie believes to be reasonable, given the apparent lack of interest in carbon regulation in Washington today.

### D. <u>Fuel Price Forecast.</u>

**1. <u>Joint Intervenors' Evidence.</u>** Dr. Ackerman testified that an evaluation of the economic viability of gas-fired vs. coal-fired generation plants depends on, among other things, the relationship between gas and coal prices. Although Duke included high and low fuel price sensitivities in its analysis, Dr. Ackerman noted that these scenarios assume that prices for different fuels move up and down together. Dr. Ackerman said that in both its high and low fuel prices scenarios, Duke assumes that the ratio of gas to coal prices is more favorable to coal as the prices go up or down from those assumed in the Base Case. Dr. Ackerman argues that Duke did not analyze any sensitivities in which fuel prices are higher or lower than the Base Case in a way that favors gas instead of coal.

Dr. Ackerman testified that there is no basis for the Company to assume that gas and coal prices will be highly correlated or that shifts in fuel prices will tend to favor coal over gas. In fact, between March 2007 and December 2011, Henry Hub natural gas prices dropped while Illinois Basin coal prices stayed relatively flat. Even going back 10 years further to 1997, the correlation coefficient between Henry Hub natural gas prices and Illinois Basin coal prices between 1997 and 2011 is only 0.12, which Dr. Ackerman asserts indicates almost no relationship between the movements of the two prices.

Dr. Ackerman further testified that fuel prices are subject to numerous uncertainties over the multi-decade time span used in this case, including geological discoveries, innovations in mining and drilling techniques, the strength of export markets, and the evolving regulatory environment for the extraction and use of both coal and natural gas, any of which could drive the price of natural gas or coal. Dr. Ackerman concludes that Duke should have considered shifts in relative prices of coal and natural gas in both directions in its analysis.

**2. <u>Duke's Rebuttal Evidence.</u>** Mr. McMurry testified that the ratio of gas prices to coal prices used for the base case was actually favorable to gas. The base case gas price was developed through a comparison of eight contemporary price forecasts. To set the upper and lower bounds for the gas sensitivity, Duke used two standard deviations above and below the mean, which resulted in approximate adjustments of +35% and -20% from the base case. The base case coal price was developed using a set of 24 different historical forecasts from leading consultants. Again, Duke used two standard deviations for the upper and lower bounds of the coal sensitivity. This resulted in approximate adjustments of +25% and -40% from the base case. Duke used a starting gas price that was lower than the mean of the other price forecasts in combination with a starting coal price that was higher than the mean of the other price forecasts for its base case. This produces a ratio of gas prices to coal prices for the sensitivity that is lower than it would be if the base case had used the mean values, which is more favorable to gas.

Mr. McMurry stated that when they developed high- and low-price sensitivities that were based on the ranges of gas prices and coal prices independently, the ratios would tend to increase due to the low base case ratio starting point. Mr. McMurry testified that any implication that Duke intentionally biased its analyses in favor of coal is incorrect. Mr. Fleck also testified that Duke's gas to coal price relationship is reasonable, given the market conditions in place today and Wood Mackenzie's best judgment of likely market developments over the forecast horizon.

### E. <u>Extended EE and Low-Load Forecast Assumptions</u>.

**1. <u>Joint Intervenors' Evidence</u>.** Dr. Ackerman testified that, in order to identify the least cost plan, Duke should have evaluated increased use of energy efficiency and demand response measures ("DSM"), expanded use of renewable energy, and purchases of energy from existing power plants as options to the proposed retrofits. Although Dr. Ackerman did not suggest that any one of these alternatives alone could replace any of Duke's coal units, he believes that Duke should be required to evaluate combinations of these alternatives in determining the least-cost alternatives to continued operation of some existing coal plants.

Specifically with regard to DSM, Mr. Ackerman pointed out that Duke assumed it would only satisfy the levels of energy savings that the Commission has already specifically required through 2020, and would achieve virtually no incremental savings thereafter. Duke's assumed energy savings plateaus in 2017 through 2019 and then plummets in 2021 and beyond.

Dr. Ackerman opined that Duke could achieve additional energy savings from DSM after 2020. In support, Dr. Ackerman noted that Indiana lags behind other states in the level of DSM savings achieved so far, which means that more opportunities for additional savings exist in Indiana than in many other states. In addition, the neighboring state of Ohio has set a standard of 22% savings by 2025, which is significantly higher than the 11.9% limit that Duke is claiming here, and a major study found that utilities could easily satisfy such a standard with proven utility programs and innovative policies. And Dr. Ackerman noted that a 2009 report of the Federal Energy Regulatory Commission found that utilities could achieve far higher levels of energy savings in Indiana as new technologies and policies develop over the next decade.

Ms. Wilson estimated that Duke could achieve 0.6% per year of DSM savings after 2020. Ms. Wilson believes that 0.6% per year is far more reasonable than Duke's assumption that virtually all additional savings would halt after 2020. This Extended EE scenario would result in a reduction of the level of new capacity that would otherwise be needed in scenarios involving the retirement and replacement of the Cayuga units. As a result, Duke's projected net benefit of retrofitting Cayuga Units 1 and 2 declines substantially.

In response to the Company's argument that its low load growth scenario could be taken as a proxy for additional energy efficiency, Dr. Ackerman noted that if this were true, then

Duke's analysis would fail to capture the risks of both lower load growth and the opportunities for increased energy efficiency, both of which exist simultaneously. Thus, in order to account for the risk of low load growth and the possibility of Duke pursuing additional cost-effective energy efficiency, Dr. Ackerman testified that Duke should add a scenario to its analysis reflecting both factors.

In addition, Dr. Ackerman pointed out that in Duke's low load growth scenario, the evaluation of retirement of the Cayuga units assumes replacement with the same amount of gas combined-cycle capacity as in the base case, even though this results in capacity far above what the Company needs to serve its customers under the low load forecast. Mr. Ackerman said that if the Company had optimized its evaluation of these retirements in the low load scenario, it would have replaced significantly less than 100 percent of the retired capacity. Mr. Ackerman believes that the Company's failure to optimize around coal plant retirement in the low load scenario biases the results against retirement.

2. **Duke's Rebuttal Evidence.** Michael Goldenberg, Manager of Customer Planning and Regulatory Strategy for Duke Energy Business Services LLC, testified that Duke developed its forecast of energy efficiency impacts to comply with the Commission's mandate through 2019. To assess the reasonableness of increasing the energy efficiency impacts beyond that level, the Company relied upon the Electric Power Research Institute ("EPRI") study titled "Assessment of Achievable Potential from Energy Efficiency and Demand Response Programs in the U.S. (2010-2030)." He explained that any significant amounts of EE impacts beyond the cumulative total required for compliance with the Commission mandate would not seem prudent because full compliance with the Phase II order mandate is at or above the Maximum Achievable Potential from the EPRI study for EE in Indiana. Mr. Goldenberg stated that to plan for and count on an expansion of energy efficiency that is not practically achievable by customers makes no sense. He said the assertion that the Company's forecast of energy efficiency growth does not expand after 2020 is incorrect. He explained that although the rate of growth in energy efficiency impacts in the Company's analysis slows after 2019, the Company reaches the mandated cumulative level of energy efficiency of 11.9% of projected retail load and then continues to maintain this same cumulative level in 2020 and beyond by forecasting the addition of new energy efficiency measures at a rate that follows the growth in the retail load. He testified that in order to maintain this level, energy efficiency programs must continue to be offered and customers must continue to adopt the measures. The end result of this assumption is that the Company's forecasted rate of load growth is reduced after 2019 through the inclusion of incremental energy efficiency impacts. Thus, under Duke's assumptions, incremental energy efficiency does not stop after 2020.

Mr. Goldenberg testified that one of the unique characteristics about energy efficiency and demand response is that the utility has to depend on its customers to take action in order for the impacts to be realized. That factor creates uncertainty around this resource that must be recognized and accounted for in planning. Mr. Goldenberg testified that Duke's planning assumptions are reasonable given the current state of the economy, the Company's prior energy efficiency efforts, and its view of the future.

Mr. Merino testified that in addition to including the incremental impacts of the Company's sponsored energy efficiency programs in its analyses, Duke's load forecast assumes that energy consumed per unit of output continues to decline in the future based on past productivity trends and changes in codes and standards. He stated that Ms. Wilson arbitrarily cut the projected rate of growth in the peak and energy load forecasts by 50%. It is not clear if the revision applied by Ms. Wilson to Duke's load forecast was driven by a different economic outlook, increased energy efficiency, or a combination of both. Mr. Merino testified that Ms. Wilson's adjustments pose the risk of double counting the impact of naturally occurring energy efficiency, which the Duke load forecast already assumes in its base case projection. Mr. Merino therefore characterized Ms. Wilson's Extended EE Case as an unrealistic lower case and an inappropriate revision of the forecast. Mr. Merino further testified that energy efficiency and load growth trends are not independent. Rather, they are connected by employment and income growth, regulatory mandates for Company-sponsored programs, economics, new codes and standards, weather, and price trends for naturally occurring energy efficiency.

### F. <u>SCR Retrofits at Cayuga.</u>

1. **<u>OUCC's Evidence.</u>** Anthony A. Alvarez, Utility Analyst in the OUCC's Resource Planning and Communications Division, testified that the OUCC opposes specific projects included in Duke's Phase 2 Compliance Plan. He stated that the OUCC opposes the installation of the equipment that is unnecessary to meet the MATS requirements, but rather is designed for compliance with environmental regulations that will not be defined for approximately five years because he believes that the plan places risks on Duke's ratepayers through higher rates.

Mr. Alvarez explained that in addition to compliance with the finalized MATS rule, Duke is requesting Commission approval for its Phase 2 compliance plan on the basis of pending environmental requirements, and the latest proposed set of environmental regulations. He stated that Duke also requests approval to retrofit and operate Cayuga 1 and 2 with SCRs, primarily as mercury oxidation devices. Mr. Alvarez testified that it is unclear whether or not SCRs will be necessary to achieve compliance with undefined, future regulations. He added that Duke provided information stating that NAAQS compliance could occur in 2019 or 2020. Mr. Alvarez testified that if the NAAQS will not be finalized until 2020, Duke cannot know what will be required as environmental controls for electric utility steam generating units until that time. He explained that installation of equipment to comply with a standard that will not be finalized until eight years in the future unfairly places financial risk on current Duke ratepayers, who will ultimately bear the costs. Mr. Alvarez testified that the OUCC's analysis concluded that Duke's proposal is, in effect, over-complying with known emission control regulations and requirements. He stated that the OUCC does not support the installation of expensive equipment to meet hypothetical standards at the expense of the ratepayers.

Mr. Alvarez discussed the various available technologies to meet the emission limits under MATS, such as electrostatic precipitators ("ESP"), fabric filters or baghouses, FGD, DSI, and ACI. Mr. Alvarez testified that the speciation of mercury in the flue gas determines how it is captured. He stated that elemental mercury is insoluble in water and as a consequence, it is not collected in a downstream FGD system or removed by particulate collectors. He added that instead, elemental mercury is removed using an ACI system or converted to another form (or speciation) before it can be captured in a downstream FGD. Mr. Alvarez testified that ACI is a viable technology for mercury reduction on coal-fired boilers and can reduce mercury emissions by more than 90%. He described how an ACI system works; the powdered activated carbon ("PAC") is pneumatically delivered from the storage silo feed system to distribution manifolds and to injection lances to achieve maximum PAC coverage of the flue gas in the ductwork where the PAC adsorbs the vaporized mercury in the flue gas stream. He stated that the mercury adsorbed PAC is then collected with the fly ash in downstream particulate collection devices, such as an ESP or baghouse.

Mr. Alvarez testified that in Cause No, 42718, Duke (then Public Service of Indiana) proposed to install ACI-baghouse technology for the Gallagher units to comply with deadlines for regulations set to occur in 2015. He stated that during that time, the OUCC raised issues because no mercury emission specific additions were needed until at least the year 2018. PSI modified its Phase I compliance plan to install baghouses at Gallagher rather than ACI-baghouse technology in the subsequent Settlement Agreement approved by the Commission.

Mr. Alvarez testified that Duke found the ACI-baghouse technology effective for mercury mitigation under the final MATS rule. He stated that the installation of baghouses with ACI at Cayuga Units 1 and 2 is a valid technical alternative with respect to the MATS rule and mercury compliance only. Mr. Alvarez testified that Duke's screening analysis shows that the net present value ("NPV") impact of installing baghouses with ACI is the most economic and efficient technology for MATS compliance. He explained that the mercury mitigation co-benefit to using SCRs is outweighed by other complicating factors, making SCRs not the best choice. Mr. Alvarez described the co-benefit derived and explained the drawbacks using the SCR system for mercury mitigation. He stated that the SCR's catalyst layer oxidizes the mercury in the flue gas and the downstream FGD effectively removes the oxidized mercury. He testified that the drawbacks of the SCR system for mercury mitigation include: the cost of installation; the presence of ammonia in the SCR inhibits the catalyst from oxidizing mercury; the SCR also transforms sulfur dioxide ("$SO_2$") to sulfur trioxide ("$SO_3$"), which inhibits the mercury adsorption effectiveness of the activated carbon; and finally, the SCR catalyst layers trap arsenic, requiring an arsenic mitigation system. Mr. Alvarez testified that should the Commission approve the Cayuga Units 1 and 2 SCR projects, the OUCC recommends that the Commission cap Petitioner's cost recovery for the Cayuga Units 1 and 2 SCRs. He stated that Petitioner may then seek cost recovery of any costs over the cap during its next base rate case.

Ms. Armstrong also presented the OUCC's recommendation to deny a large portion of Duke's overall CPCN request of $447.844 million for the Phase II Environmental Compliance Plan. Ms. Armstrong testified that the OUCC concluded the SCRs on Cayuga Units 1 and 2, the $SO_3$ mitigation systems on Cayuga Units 1 and 2, and the ACI systems on Gibson Units 1-4 were not necessary to meet environmental regulations at this time. She stated that impending environmental regulations, Duke's historical emissions, the results of Duke's recent emissions testing, and the cost and effectiveness of other mercury control technologies do not support the need for these projects.

Ms. Armstrong testified that both Cayuga Units 1 and 2 have FGDs installed, which are effective for controlling oxidized mercury. She stated that Duke's emissions testing over the 2010-2011 timeframe shows that Cayuga's flue gas stream prior to entering the FGD is already primarily oxidized mercury. She stated that the goal of adding an SCR to this process is to increase the amount of oxidized mercury present in the flue gas stream so that the FGD can more effectively remove it, but noted that even if Duke might be able to convert all of the elemental mercury to oxidized mercury prior to entering the FGD, the FGD will generally remove only 80% of the resulting oxidized mercury.

She explained that the goal of ACI is to bind mercury, whether oxidized or elemental, to the surface of the carbon particles so that they can be removed by an ESP or baghouse. She testified that the mercury removal efficiency of ACI ranges from 70% to 90%. She reasoned that if ACI was applied to the remaining elemental mercury in the flue gas stream, the incremental mercury removal of the ACI does not differ significantly from the mercury removal associated with the SCR. She stated that the main difference between these technologies is that an SCR is a more capital intensive option, while an ACI system's costs rest more in the actual operation of the equipment. She also noted that SCRs have the added benefit of controlling $NO_x$ emissions.

Ms. Armstrong noted that Duke is building redundancy into the configuration of Cayuga by asking for the SCRs, mercury re-emissions control, and the ACI system. She reasoned that if one of these control systems fails, there will be two more mercury control systems in place that can operate. This may allow Cayuga to remain in compliance while operating at higher capacity factors than it has historically operated. While this will assist the Cayuga facility to operate at higher loads if Duke chooses to dispatch this unit more in the future, she noted that the OUCC questions whether these expenditures are worthwhile and necessary. She noted that ratepayers would pay approximately $35 to $45 million more per year to operate the Cayuga SCRs at full load under any condition during any part of the year. Since Cayuga has operated at capacity factors between 55% and 70% over the past five years, she stated that operating Cayuga at a higher capacity factor may not be necessary or reasonable and explained that the OUCC questions whether it would be wiser instead to hedge against the potential failure of Cayuga's control technology with capacity and power purchases.

Ms. Armstrong also testified to the advantages and disadvantages of operating an SCR system. She said that the main downside to SCR operation is that it can generate the blue plume phenomenon resulting in arsenic poisoning of the unit. These issues result in additional capital and O&M costs in operating the SCR. She explained that the OUCC accounted for the capital and operating costs of the arsenic mitigation and $SO_3$ mitigation systems that must be included in its cost comparisons of the SCR and ACI. She noted that the $SO_3$ mitigation system may still be needed to improve the effectiveness of the ACI, as any $SO_3$ in the flue gas will compete with mercury for adsorption sites on the activated carbon. Ms. Armstrong also noted that the lengthy tie-in schedule for an SCR is another disadvantage to installing the technology on Cayuga Units 1 and 2. She stated that the Midwest Independent Service Operator ("MISO") is concerned that as units are taken offline to complete MATS retrofits, the risk of a major loss of load event will be greater during the "shoulder months" of 2012 through 2015 than it has at any other time in MISO's operating history. She noted that Cayuga Units 1 and 2 each have a generating capacity of about 500 MW, and taking these units offline ahead of when the SCRs are truly needed will only exacerbate this problem. Finally, she explained that both the capital and operating costs of the SCR are much greater than operating ACI.

Ms. Armstrong stated that the main advantage of the SCR is that the equipment will also substantially decrease the $NO_x$ emissions from Cayuga Units 1 and 2. She noted Duke's position that it can avoid a baghouse on Cayuga Units 1 and 2 to meet MATS deadline and comply with potential future lower 8-hour Ozone NAAQS limits by moving up the installation date of the SCRs. However, Ms. Armstrong questioned whether or not Duke will have to install an SCR at Cayuga in the future because of the 8-hour Ozone NAAQS. She stated many events must take place before this requirement would occur. First, she said the EPA has to review the existing NAAQS and scientific literature and make a determination that the current 8-hour ozone standard of 75 ppb is not enough to protect public health and welfare. Then, the EPA needs to determine what level the NAAQS should be set at to provide an adequate margin of safety for public health. She noted that the EPA would likely release this decision in a proposed ozone NAAQS rule, which would be subject to a public notice and comment period. She explained that once the final ozone NAAQS is issued, which many believe will not occur until toward the end of 2014, states will have one year to submit their ozone designations for attainment and non-attainment areas with the new NAAQS. States will also have three years to submit their revisions to the their state implementation plans ("SIPs") for meeting the new NAAQS, and the EPA must approve the SIP before it takes effect.

Ms. Armstrong further explained that after the EPA sets a new NAAQS, the state would have to determine that the county or air quality control region in which Cayuga is located did not meet the new NAAQS. She showed that the air quality control region ("AQCR") in which Cayuga is located had 3-year design values for ozone during 2008-2010 at or below 70 ppb and below 67.5 ppb in 2009 and 2010. She noted that the Wabash River Generating station is also located in this AQCR and suggested that Duke's planned retirement of these units could also have a substantial impact on this region's air quality. She stated that there are a few other electric generating units within the region that may be retired in 2015 as a result of MATS, and indicated these retirements could lead to a further decrease in ambient ozone concentrations. She concluded that it was speculative to say that Vermillion County would be listed as being in non-attainment for the future ozone 8-hour NAAQS.

Ms. Armstrong argued that even if Vermillion County was designated as being in non-attainment with the future ozone NAAQS, the state still has a choice in how it will bring the area back into attainment. She explained that in the event Vermillion County is designated as a non-attainment area, Cayuga would be required to install reasonably available control technology, but the state also has the choice in defining what control technologies qualify as reasonably available. She asserted that the entire process could take years with no clear definition of the NAAQS standard, during which ratepayers would be paying approximately $50 to 55 million a year.

Ms. Armstrong testified that Duke did not provide enough evidence for the OUCC to verify Duke's assertion that a baghouse would be required for MATS compliance in the absence of an SCR on Cayuga. First, she noted that since Duke has not tested ACI and mercury re-emissions chemicals simultaneously on Cayuga Units 1 and 2, the combined performance of these technologies on Cayuga's mercury emissions is not known. She asserted that understanding the combined performance of ACI and mercury re-emissions additives is important because the installation of baghouses is not necessary if both technologies reduce Cayuga Units' 1 and 2 monthly-average mercury emission rates to below 1.2 lb/TBTU. She conceded that a baghouse may be necessary to employ ACI at higher injection rates, as the existing ESPs may be unable to capture the additional sorbent being injected into the system. She also noted that baghouses could be needed if ACI is used, as the baghouse provides a longer residence time for the ACI to react with mercury in the flue gas. She stated that higher AC injection rates on Cayuga Units 1 and 2 must first be tested and found to be ineffective in controlling mercury emissions to the magnitude necessary under MATS before the OUCC can confirm that baghouses would be necessary on Cayuga Units 1 and 2 in the absence of the proposed SCRs.

Ms. Armstrong stated that based on Duke's coal-fired units' historical emissions, the SCRs are unnecessary to meet CAIR. She stated that even if Cayuga Units 1 and 2 were to operate at 80% of their maximum designed heat input, Duke's $NO_x$ shortfall would be approximately 2,800 tons per year. She noted that this shortfall could be replaced by allowance purchases. She showed that price of $NO_x$ allowances would have to increase dramatically before the SCRs on Cayuga Units 1 and 2 would make sense economically.

Ms. Armstrong supported the installation of mercury re-emission systems on Cayuga Units 1 and 2 because the testing data showed that the FGDs on Cayuga are experiencing mercury re-emission issues significant enough to impact Cayuga's overall mercury emissions by more than 20%. She stated that the mercury re-emissions chemical injection system will enhance the Cayuga FGDs' mercury removal significantly at a relatively low cost.

Ms. Armstrong also supported the installation of ACI systems on Cayuga Units 1 and 2. She reasoned that even if the mercury re-emissions chemical performed at its maximum capability, adding the ACI will provide additional operational flexibility to Cayuga Units 1 and 2 by increasing the total mercury removal efficiency of those units. She discussed the ACI testing conducted on Cayuga Unit 1 in more detail to suggest that the ACI could provide significant incremental mercury removal on these units. She concluded that ACI is a wise choice to install on Cayuga Units 1 and 2 for mercury control, even if this system may add some redundancy to the planned control technology configuration for those units.

Ms. Armstrong noted that the advantage of the ACI system is that the majority of costs associated occur during its operation. Even if the system does not operate that often, ratepayers will not be contributing a significant amount of money because the capital costs of the ACI system are low. She noted that main disadvantage of relying on ACI for mercury removal is that Duke may need to install baghouses on Cayuga. She explained that baghouses could become necessary if the company finds that it needs to increase the injection rates of the AC and the existing ESPs are unsuitable for capturing the additional particulate loading on the system. She testified that the addition of baghouses to Cayuga Units 1 and 2 could potentially bring the ACI option's overall costs more in line with the costs of the SCR option. However, she noted that the higher AC injection rates were not tested, so it is not known if the baghouse would be necessary. She recommended Duke conduct additional testing on these units to see if the existing ESPs can handle higher AC injection rates and if the higher injection rates are able to remove enough mercury to bring Cayuga into compliance with MATS.

2. **Duke's Rebuttal Evidence.** In rebuttal, Mr. Miller testified that Duke performed significant testing and analysis to reach its conclusion that the proposed compliance plan for Cayuga is the most robust investment over time for its customers. First, Duke learned about the factors impacting the effectiveness of ACI on mercury removal, and tested to determine those factors' impact on ACI effectiveness at Cayuga. Second, once Petitioner learned that mercury re-emissions were occurring at Cayuga, it performed extensive testing to determine a solution. Mr. Miller testified that its testing demonstrated that the re-emissions chemical only controls mercury to the level of the oxidized mercury entering the wet scrubber. The re-emissions chemical keeps the oxidized mercury in a state where it cannot transform to the elemental state, but the chemical's level of mercury control is limited by the amount of oxidized mercury coming into the scrubber. Mr. Miller testified that the scrubber cannot remove mercury beyond the level of oxidized mercury coming in. Third, the Company determined through testing and analyses that the combination of ACI and mercury re-emissions chemical additives cannot guarantee compliance with mercury MATS standards – either a baghouse (which increases the effectiveness of ACI and DSI) or an SCR (which provides the necessary mercury oxidation) is necessary. Fourth, because either a baghouse or SCR is necessary to ensure MATS compliance, Duke's economic modeling indicates that the more cost effective option for customers is for Duke to install the SCRs at Cayuga now rather than install the baghouses now and likely install the SCRs at Cayuga within the next ten years to comply with more stringent $NO_x$ regulations. Mr. Esamann further explained that no baghouse projects are expected to be needed on Cayuga if the Company constructs the SCRs today. If the Company constructs SCRs on Cayuga units now, the SCRs do "double duty" by controlling mercury to comply with MATS today and controlling $NO_x$ to comply with future ozone NAAQS or other requirements in the near-term.

Mr. Miller testified that Petitioner compiled actual mercury emission data from Cayuga using the mercury CEMs which allowed Petitioner to plot Cayuga's mercury emissions over 30-day rolling averages, which is how it must comply with MATS. This is real data gathered from Cayuga, reflecting actual unit operations across all load ranges and not just full load values. He testified that this data showed that the OUCC's proposed compliance plan of ACI (at 70% mercury removal) and mercury re-emission chemical would likely result in Cayuga Station (based on CEMs data) being out of compliance approximately half of the time.

Mr. Miller also testified that for ACI to be optimally effective, the flue gas temperature should be between 280 and 310 degrees Fahrenheit. Mr. Miller testified that Cayuga's higher flue gas temperature of 330 degrees Fahrenheit reduces the capture of mercury by activated carbon. He also noted that the Cayuga units have a higher $SO_3$ emission rate of between 15 and 20 ppm. He stated that ACI works best with an $SO_3$ of below 5 ppm, and ACI is not as effective at Cayuga because of the $SO_3$.

Mr. Miller also discussed residence time, which is the amount of time for chemical reactions to occur in the flue gas. He noted that residence time is important for the effective use of ACI, and that the proposed Cayuga SCR would afford the additional residence time by slowing down the flue gas so that the mercury could be oxidized by the vanadium in the catalyst and captured in the scrubber. Therefore, the SCR offers the double benefit of capturing both NOx and mercury.

When asked why Duke had not considered a baghouse to accomplish these reductions, Mr. Miller testified that the SCR resolved the mercury challenge at Cayuga as well as the reduction of $NO_x$. Mr. Miller stated that the reduction of $NO_x$ limits Duke's exposure to future ozone NAAQS reductions. Mr. Miller stated that in his role as environmental compliance planner, he felt that Duke was fortunate to have one control technology that addresses both mercury and $NO_x$.

Mr. Miller also testified that the Cayuga units were built on a very small footprint per megawatt, and that Duke went as far upstream in the flue gas as possible to try and increase residence time for the ACI. Even then, the residence time was around one second, which was too short. He stated that for ACI to be more effective at Cayuga, Duke would also need to install dry sorbent to reduce the $SO_3$, which must be done before the injection of activated carbon, and there is not time to do both of those things at Cayuga as it's configured right now.

Mr. Miller also explained why Ms. Armstrong's suggestion that Petitioner consider a combination of ACI, mercury re-emissions chemical system, and operating a unit at a lower load to decrease emissions and supplementing the capacity and power to comply with MATS is infeasible. Mr. Miller testified that periodic or permanent derates at Cayuga are not cost effective or feasible options for compliance purposes. Duke must design its compliance plan around worst case, full load emission rate performance – not because it plans to increase operations at Cayuga, but because of the short 30-day rolling average period allowed by the MATS rule. He testified that over this short allowed period, Petitioner must consider the need for the units to be able to generate at high load over an extended period of time, during hot summertime conditions, for example. Duke designed its compliance plan to serve the load needs of its customers, which for the MATS rule means designing for full load. Mr. Miller also testified that the Company would be highly concerned that regular or extended derates for MATS compliance could result in a circumstance where the units would not be allowed to generate at higher loads again in the future because of the potential to trigger the EPA's New Source Review rules. Further, attempting to meet MATS requirements by derating the units would present complicated operational issues that would be susceptible to error.

Mr. Miller testified that based on its testing data and the available industry data on the factors impacting ACI's effectiveness, Petitioner does not have reason to believe that increasing the injection of activated carbon at Cayuga would result in sufficient removal of mercury to comply with MATS. In addition, Mr. Miller stated that increased activated carbon on any precipitator, especially a smaller precipitator such as Cayuga's, increases the risk of increased PM emissions from carbon carry-through to the scrubber.

### G. Cost Estimate for Cayuga SCR Projects.

**1. OUCC's Evidence.** Maclean Eke, Utility Analyst in the OUCC's Resource Planning and Communications Division, testified that his review of the Cayuga project led him to conclude that the contingency estimate was rather small. He stated that there are more than 700 individual work items in the project, but that Duke identified only 13 items in the contingency estimates. Mr. Eke noted that the OUCC could not analyze the cost effectiveness of the Duke contingency models, because the OUCC was unable to replicate Duke's calculations. Therefore, the OUCC could not support the Duke cost drivers applied in the contingency calculations of the Cayuga compliance project.

Mr. Eke explained that Duke included construction rental equipment costs in the cost estimates for the compliance project, but did not explain the inclusion of costs when the OUCC requested follow-up in discovery. Mr. Eke stated that Duke added costs for "Means and Methods" in the Cayuga compliance cost estimate. Mr. Eke testified that Duke's projected overtime cost was excessive, because the proposed 7-12 (seven–day twelve hour) work week doubles the cost of labor without a guarantee of efficiency or production.

Mr. Eke also testified about Duke's proposal for roads at Cayuga. He stated that rather than Duke's lesser proposal, he recommended the construction of a full-depth asphalt road because it will withstand heavy traffic without additional maintenance and will remain durable for the expected 20 years of the project. Mr. Eke also recommended that the Commission deny Duke's requested overtime and make the scaffolding costs estimate a fixed amount instead of a percentage of the labor cost.

Ray L. Snyder, Utility Analyst in the OUCC's Resource Planning and Communications Division, expressed the OUCC's concerns regarding the CPCN project cost estimates filed by Duke. He stated that the OUCC agrees that the level of project definition Duke has provided supports the Class 2 classification of the estimate with an accuracy range of -15% to +20%. However, the OUCC maintains that Duke's estimates contain inaccurate assumptions and unreasonable inputs. Mr. Snyder explained that Duke obtained project cost estimates from Sargent & Lundy ("S&L") and Burns and McDonnell ("B&M"). Mr. Snyder stated that the B&M estimate was a review of only part of the costs of the total project, and therefore could not effectively be compared to the estimate provided by S&L. He added that a third party, Mr. Colin Tattam, also provided a review of only part of the project costs. Mr. Snyder testified that Duke chose to use the project estimate increases recommended by Mr. Tattam but ignored decreases recommended by B&M, resulting in an inflated project estimate. Mr. Snyder recommended the Commission not accept Duke's estimate, which would result in higher costs to ratepayers.

**2. <u>Duke's Rebuttal Evidence</u>.** Mr. Renner testified that as supplier pricing comes in and contracts are awarded, Duke's project estimate is proving to be a reasonable representation of what actual costs are expected to be. Duke has already signed contracts with its vendors for major equipment on the SCR projects. He testified that the single largest unknown cost within the estimate continues to be the firm price, lump sum, General Works Contract ("GWC"), which is currently in the bid process. The bids sought for the GWC are firm price, guaranteed schedule, which would place the majority of cost overrun risk on the shoulders of the successful GWC bidder. Mr. Renner explained that the GWC includes all the construction and erection of the SCRs from the top of structural foundations and balance of plant equipment. The GWC contractor will be required to supply all construction labor, subcontracts, tools, construction equipment (including large cranes), scaffolding and bulk materials (including insulation), heat trace, cable, conduit, cable tray, and any consumable materials that might be required to complete the project. Mr. Renner testified that Petitioner does not believe a cap on project costs is reasonable or necessary when developing projects such as these.

Mr. Renner responded to Mr. Eke's concerns about Duke's risk analysis. Mr. Renner testified that Duke has carefully assessed the potential range of risks on the SCR project, followed industry guidelines published by the Association for the Advancement of Cost Engineering in developing the estimated contingency, plans to adopt a contracting approach with an eye towards risk mitigation, and believes that Petitioner's 15.4% proposed contingency amount is reasonable. Mr. Renner explained that Duke performed a typical range estimating simulation analysis, also known as a "Monte Carlo" analysis. Separately, S&L conducted its own version of a simulation analysis, which resulted in similar contingency recommendations. Mr. Renner testified that Petitioner's estimate was a result of rigorous analysis and he believes that it is the appropriate contingency estimate to use on the project.

In response to Mr. Eke's recommendation that the Commission deny Petitioner's estimated overtime amounts, Mr. Renner testified that the amount assumed in Duke's estimate is a reasonable approximation and that eliminating the possibility of any overtime, as suggested by Mr. Eke, does not reflect the reality of construction and should be rejected by the Commission. Mr. Renner testified that it is certainly reasonable to assume some level of overtime will be required, both to attract and maintain a work force, as well as manage outage requirements for critical path items and reduction of the time the unit is out of service.

### H. <u>Deferred Accounting</u>.

**1. <u>OUCC's Evidence</u>.** Wes R. Blakley, Senior Utility Analyst in the OUCC's Electric Division, explained that if certain criteria are met, utilities may seek special authorization from the Commission to accrue carrying charges and defer depreciation. These adjustments benefit the utility's financial reporting. He added that the utility's accrual of carrying charges reduces its interest expense, and the deferral of depreciation delays depreciation expense from hitting the utility's income statement. This therefore provides financial statement relief until the time the assets can be included in base rates and the utility can begin recovering a return on and of the asset through depreciation recovery. Mr. Blakley noted that when the Commission considers a request for post-in-service accounting treatment, it considers the amount of earnings erosion a utility would suffer if the special accounting treatment is not granted.

Mr. Blakley said that the Commission has denied requests for post-in-service accounting treatment where significant earnings erosion was not demonstrated. He noted that in the Final Order in Cause No. 43874, the Commission stated that a utility must provide evidence that without AFUDC it would incur material earnings erosion, even when it has costs that may be eligible for capitalization as a regulatory asset for future recovery in rates per Generally Accepted Accounting Principles ("GAAP"). He noted that the Commission also found that earnings erosion should be viewed in the context of the utility's operations as a whole.

Mr. Blakley added that it is within the purview of the Commission to ultimately decide whether the evidence indicates material earnings erosion that will negatively impact Petitioner financially. He noted that Duke provided no evidence of the potential for, or amount projected of, material earnings erosion in this case. He believes the Commission should therefore deny Duke's request to record a deferral for post-in-service depreciation, carrying costs, and O&M expense for the Phase 2 projects.

2. **Duke's Rebuttal Evidence.** Mr. Freeman testified that the Company's deferral request is specifically provided for by the Clean Coal Technology Statutes under which the Company is seeking approval. Ind. Code § 8-1-8.8-5 defines "costs associated with qualified utility system property" as capital, operation, maintenance, depreciation, tax costs, and financing costs of or for qualified utility system property. Thus, Mr. Freeman argues the financing costs the Company is requesting to defer are explicitly included in the definition of qualifying costs and are incurred during the operation of the facility. Further, Ind. Code § 8-1-8.8-12 provides that the Commission shall allow a utility to recover the costs associated with qualified system property so long as the utility provides substantial documentation that the expected costs and expenses and the schedule for incurring those costs and expenses are reasonable and necessary. Mr. Freeman testified that, as permitted by the Clean Coal Technology Statutes, the Company should be allowed to recover all financing costs as CWIP revenues, AFUDC, or post-in-service carrying costs.

Mr. Freeman also testified that requiring Commission consideration of earnings erosion creates an inconsistency with the Clean Coal Technology Statues. Without the deferral, the Company would be able to recover the carrying costs until the in-service date, either through AFUDC or through CWIP revenues. With the tracking mechanism provided for in Ind. Code § 8-1-8.8-12, after the facility is in-service, the carrying costs would be recovered in the next semi-annual filing that includes the plant balance. If the deferral of these post-in-service carrying costs is not permitted, there is a limited period of time, approximately 6-12 months, during which the financing costs would not be recovered. He testified that it is inconsistent and contrary to statute to deny financing cost recovery during this interim period. In addition, if the costs are recovered pursuant to a tracker mechanism, by definition the earnings erosion impact will be minimized. Mr. Freeman testified that without approval of the deferral, the Phase 2 equipment will be providing service to customers while the Company continues to incur financing costs associated with the equipment, with no carrying cost recovery to offset the financing costs. Mr. Freeman further testified that the Commission has approved the deferral of post-in-service carrying costs on the Company's Phase 1 environmental compliance plan, combined Cause Nos. 42622 and 42718, and in the Company's environmental plan, combined Cause Nos. 41744-S1 and 42061.

7. **Commission Discussion and Findings.**

A. **Approval of Duke's Phase 2 Environmental Compliance Plan.** Based on the evidence of record, we find Duke's Phase 2 Environmental Compliance Plan, as revised in its rebuttal testimony, is reasonable and necessary and should be approved. Neither the OUCC nor Joint Intervenors contested that Duke will have to meet more stringent emission limits in the near future. Rather, the OUCC argued that some of the proposed methods for meeting those requirements, namely, the Cayuga SCR and DSI systems and the Gibson Units 1-4 ACI systems are unnecessary. Joint Intervenors, on the other hand, argued that Duke's IRP modeling was flawed in several ways, which led to incorrect conclusions that installing environmental controls on Cayuga and Gallagher Stations were more cost effective than retirement of those generating units.

Ms. Armstrong recommended denying Duke's request for the Cayuga SCR and $SO_3$ mitigation systems and the Gibson Units 1-4 ACI systems. Ms. Armstrong testified that these projects were not likely necessary for MATS compliance based on her analysis of data obtained from the EPA's Toxic Release Inventory ("TRI") and Clean Air Markets Database. Ms. Armstrong recommended that Duke perform additional monitoring of its units' emissions to provide more insight into what emission rates can be expected and report back.

Mr. Geers explained that the TRI and other publicly available mercury data is not practical to use to predict future compliance at Duke's units because Duke will be required to demonstrate compliance with MATS through actual monitored emissions data gathered by continuous emissions monitors and/or emissions testing. He also noted that TRI data does not involve direct measurement of the emissions at Duke's units. Mr. Miller said that Duke had obtained mercury CEMs data for Cayuga Station starting in March 2012. He argued that, based on the CEMs data from Cayuga Station, the OUCC's recommendations would put Duke at serious risk of non-compliance with MATS. However, Mr. Miller testified that Duke is willing to defer investment in ACI systems at Gibson units 1-4 and Gallagher Station in order to perform the additional testing and emission monitoring suggested by the OUCC.

Mr. Miller also explained why the proposed compliance plan for Cayuga is the most effective and efficient means of compliance based on significant testing and analysis. He testified that Duke first learned about the factors impacting the effectiveness of ACI on mercury removal, and tested to determine those factors' impact on ACI effectiveness at Cayuga. Second, Duke investigated and developed a solution to reduce mercury re-emissions at Cayuga. Third, Duke determined through its testing and analysis that the combination of ACI and mercury re-emissions chemical additives cannot guarantee compliance with MATS – either a baghouse (which increases the effectiveness of ACI and DSI) or an SCR (which provides the necessary mercury oxidation) is necessary. Mr. Miller testified that fourth, if either a baghouse or SCR is necessary to ensure MATS compliance, Duke's economic modeling shows that the most cost effective option for customers is for Duke to install the SCRs at Cayuga now rather than install the baghouses now and likely install the SCRs at Cayuga sometime in the next 10 years. Mr. Esamann went on to explain that no baghouse projects are expected to be needed on Cayuga if Duke constructs the SCRs today. He stated that if Duke constructs SCRs on Cayuga units now, the SCRs do "double duty" by controlling mercury to comply with MATS and controlling $NO_x$ to comply with any future ozone NAAQS or other requirements.

At the evidentiary hearing, Mr. Miller further explained that Cayuga Station has high levels of $SO_3$ in its flue gas, which inhibits the effectiveness of ACI. Mr. Miller also testified that there is limited residence time at the Cayuga units to allow for chemical reactions to take place. Either an SCR or a baghouse could provide additional residence time, but the SCR is Duke's preferred option because it largely resolves mercury compliance at Cayuga and can also reduce $NO_x$ and limit exposure to future Ozone NAAQS requirements.

Based on our review of the evidence, we find that Duke performed extensive testing and analysis of the potential options for MATS compliance at its generating units. The effectiveness of ACI for mercury removal appears to vary on a unit-specific basis, and Duke has looked closely at its potential effectiveness at Cayuga. The mercury CEMs data provided in Mr. Miller's rebuttal testimony demonstrates the actual mercury emission reductions needed at Cayuga to ensure MATS compliance on a consistent, 30-day rolling average basis. Duke provided substantial evidence that, given the specific characteristics of Cayuga Station, either baghouses or SCR systems would be needed for MATS compliance. Duke also provided evidence indicating that its modeling demonstrated the most economic option for customers under that scenario would be to install its proposed compliance plan at Cayuga now, instead of baghouses for mercury compliance now and potentially SCR systems in the future for $NO_x$ reductions. We agree that taking advantage of the co-benefit of mercury and $NO_x$ removal from SCR technology makes sense in this circumstance. We also recognize that, through their post-hearing briefing in this matter, the OUCC has subsequently endorsed Duke's Phase 2 environmental compliance plan, as revised in Duke's rebuttal testimony. As such, we find Duke's proposed compliance plan for Cayuga to be reasonable and necessary. Similarly, we find that Duke's proposed compliance plan for Gibson Station is supported by substantial evidence, and note that Duke tailored its plan for Gibson to coincide with the OUCC's recommended approach.

Joint Intervenors provided testimony discussing Duke's IRP modeling for Cayuga and Gallagher Stations. Because Duke has since withdrawn its request related to Gallagher from consideration in this proceeding, we will only discuss the modeling of Cayuga. Ms. Wilson discussed several concerns she had with Duke's analysis, including that Duke had two flawed assumptions in its IRP modeling: (1) the assumption that Duke's efforts at EE will decline steeply at the end of 2019; and (2) the use of a $CO_2$ emissions allowance price forecast that is at the low-end of the range of utility price projections. Ms. Wilson adjusted Duke's peak load to assume half of the annual growth (0.6% compared to the 1.2% annual growth assumed by Duke) as a means of demonstrating new energy efficiency measures after 2019. Installing Duke's proposed compliance measures at Cayuga remained the most cost effective option for customers after making this adjustment. Ms. Wilson also used higher carbon prices starting at 2020 than those assumed by Duke. This change caused the benefits of controlling Cayuga to turn negative, meaning that combined cycle replacement generation would be more economic.

Mr. Merino argued that Ms. Wilson's energy efficiency assumptions are far too aggressive. Mr. Merino testified that Duke's load projections already include estimated energy efficiency impacts associated with Duke's plan to comply with the Commission's Phase II Order in Cause No. 42693. In addition, he stated that Duke's base load projection includes energy efficiency impacts from the projected improvement in the average efficiency of the appliance stock, new lighting standards, and from expected productivity trends in manufacturing and service-related processes. Mr. Merino testified that Ms. Wilson arbitrarily cut the projected rate of growth in peak and energy load forecasts by 50%, which is an unrealistic and inappropriate revision of the forecast.

Mr. Goldenberg emphasized that Duke's energy efficiency planning assumptions are reasonable given the current state of the economy, Duke's prior energy efficiency efforts, and

Duke's view of the future. Mr. Geers supported the reasonableness of Duke's forecast of $CO_2$ prices and stated that Joint Intervenors presented no new information relating to the prospects for potential climate change legislation and potential future $CO_2$ prices that justifies adjustment of either the timing or prices used by Duke in its modeling analysis for this proceeding.

Based on our review of the evidence presented in this proceeding, we find that the evidence presented supports Duke's economic modeling efforts and results, and reasonably addresses Joint Intervenors' concerns. Joint Intervenors are correct that changing certain assumptions about the future will impact the cost effectiveness of installing pollution control equipment on existing coal units. However, this fact does not by itself render Duke's modeling unreasonable. The evidence demonstrates that Duke reasonably considered the impacts of both energy efficiency and carbon prices on its proposed compliance plan. The exact nature of carbon regulations and the date they might take effect is uncertain. Congress has not passed any definitive legislation requiring the limitation of carbon emissions. Further, while the EPA has proposed restrictions on carbon emissions from new power plants, any potential regulations concerning existing power plants is speculative in terms of both timing and result. Given what we know today and the evidence presented in this proceeding, we find that the assumptions used in Duke's economic modeling are reasonable.

Based on our discussion above, we find that the evidence, including the costs represented, demonstrates that Duke's proposed Phase 2 Plan is a cost-effective method of complying with the MATS requirements. Duke adequately considered all compliance options, including increased energy efficiency and renewable generation. Therefore, we approve Duke's proposed Phase 2 Plan for compliance with MATS, including the construction and use of various emission reduction equipment, as described above and subject to the findings below.

**B. <u>Clean Coal Technology Certificate of Public Convenience and Necessity</u>.** Duke requests the issuance of a CPCN for clean coal technology for its proposed SCR and DSI systems. Under Ind. Code § 8-1-8.7-4(b), in order to issue a CPCN, we must make the following findings:

> (1) Public convenience and necessity will be served by the construction, implementation, and use of clean coal technology;
>
> (2) Approve the estimated costs;
>
> (3) The facility where the clean coal technology is employed:
>
> A. Utilizes and will continue to utilize Indiana coal as its primary fuel sources; or
>
> B. Is justified, because of economic considerations or governmental requirements, in utilizing non-Indiana coal; after the technology is in place; and

(4) Make a finding on each of the factors described in Ind. Code § 8-1-8.7-3(b), including the dispatching priority of the facility to the utility.

Ind. Code § 8-1-8.7-3(b) sets forth nine factors, each of which we will consider.

1. **The cost for the clean coal technology compared to conventional emission reduction facilities.** Mr. Miller explained that there were no conventional technologies for reducing $NO_x$ or $SO_3$ emissions in general use in the United States in 1989, and no technologies that could reduce $NO_x$ to the levels expected from SCRs or $SO_3$ emissions to the levels expected from Duke's proposed DSI system. Duke performed analyses showing that these projects were the most cost-effective option for compliance with EPA regulations. Consequently, we find Duke's choice of clean coal technology reasonable.

2. **Whether the clean coal technology projects will extend the useful life of existing generating facilities.** Mr. Miller testified that, while these installations will not, in and of themselves, increase the lives of the units, they will preserve their operating lives. Mr. Geers explained that if Duke cannot meet the MATS rule emission limits, it would be forced to shut down any non-compliant generating units. Therefore, we find that the proposed clean coal technology projects will extend the useful economic life of Duke's generating facilities.

3. **The potential reduction of sulfur and nitrogen based pollutants achieved by the proposed clean coal technology system.** As previously discussed, the evidence demonstrates that the clean coal technology projects will allow Duke to reduce its air emissions sufficiently to comply with MATS.

4. **The reduction of sulfur and nitrogen based pollutants that can be achieved by conventional pollution control equipment.** The evidence demonstrates that reduction of air emissions by conventional technology would be insufficient to bring Duke into compliance with MATS or would be more expensive.

5. **Federal sulfur and nitrogen based pollutant emission standards.** The evidence demonstrates that these projects will enable Duke to comply with the MATS rule.

6. **The likelihood of success of the proposed project.** Duke's analysis demonstrates that these projects will allow Duke to achieve compliance with MATS. Consequently, we find the likelihood of success of the proposed clean coal technology projects is high.

7. **The cost and feasibility of the retirement of an existing generating facility.** Duke is proposing to retire its Wabash River Units 2-5 as part of this proceeding. The evidence demonstrates that Duke considered retirement of existing facilities in its analyses and that, based on the reasonable assumptions Duke used in its analysis, retirement

of the electric generating facilities at which Duke proposes to install clean coal technology is not the most cost effective way of complying with MATS.

8. **<u>The dispatching priority for the facility utilizing clean coal technology</u>.** Mr. Miller testified that the addition of the proposed equipment is not expected to significantly change the dispatching order of the units.

9. **<u>Other factors</u>.** Other factors supporting approval of the proposed clean coal technology projects are discussed elsewhere in this Order.

In addition to the above findings, we must address the three remaining required findings in Ind. Code § 8-1-8.7-4(b). We note that a finding that a project will serve public convenience and necessity and the approval of the estimated costs for that project are separate and distinct components of an approved CPCN. With respect to public convenience and necessity, it is appropriate to consider the project cost with its inherent range of accuracy to determine a project's viability, which differs in our review of the present cost estimate for which a utility seeks approval. We discuss each separate component below.

1. **<u>Public convenience and necessity will be served by the construction, implementation, and use of clean coal technology</u>.** As we explained in our Phase I Order in Cause No. 44012, "the initial granting of a CPCN depends in large part upon the economic efficacy of a proposed project, and as such, the initial cost estimates are a significant factor in the Commission's decision making process." *N. Ind. Pub. Serv. Co.*, Cause No. 44012, 2011 Ind. PUC LEXIS 387, at *50 (IURC Dec. 28, 2011). In its January 4, 2013 Response to the Commission's December 28, 2012, Docket Entry, Duke supplied a Confidential Exhibit 2, which listed the Phase 2 projects being proposed and the associated estimated cost of each of the projects. The total cost of the Phase 2 projects was $394,148,000. Mr. Renner described Duke's Phase 2 cost estimate as a "Class 2 estimate," and stated that the expected accuracy range is between +5% and +20% on the high end and between -5% and -15% on the low end. In its January 4, 2013 Response, Duke confirmed that this accuracy level was still valid for the revised Phase 2 cost estimate.

Based on the findings made by the Commission above regarding the analysis Duke provided in support of its proposed CPCN request, we find that the public convenience and necessity requirement is met so long as the final cost of the proposed projects, excluding AFUDC, does not exceed the upper boundary of the range provided by Duke (+20%). As noted below, through this order we are approving the recovery of Duke's estimated project costs depicted in its Confidential Exhibit 2. Therefore we conclude that public convenience and necessity will be served by Duke's construction, implementation, and use of the proposed projects based on the estimated cost and range of accuracy of the associated analysis provide by Duke.

2. **<u>Approval of Estimated Costs</u>.** Duke requests approval of the cost estimate for its Phase 2 Compliance Plan projects as set forth in its Confidential Exhibit 2. The total Phase 2 Plan construction cost is $394,148,000.

Ind. Code § 8-1-8.7-4(a) states: "As a condition for receiving the certificate required under [Ind. Code § 8-1-8.7-3], an applicant must file an estimate of the cost of constructing, implementing, and using clean coal technology and supportive technical information in as much detail as the commission requires." In addition, before we may grant Petitioner a CPCN for the Phase 2 Projects, we must approve the estimated costs. Ind. Code § 8-1-8.7-4(b).

The evidence presented demonstrates that Duke's cost estimate for the Phase 2 Projects, as depicted in Confidential Exhibit 2, are reasonable. Based on the evidence, we find that the Phase 2 Projects offer substantial potential to cost effectively reduce pollutants in a more efficient manner than conventional technologies in general use as of January 1, 1989. We have also considered the other enumerated factors set forth in Ind. Code § 8-1-8.7-3 and made the required findings under Ind. Code § 8-1-8.7-4(b). Therefore, we approve Duke's request for a CPCN for the Phase 2 Projects at an estimated cost of $394,148,000, as depicted in Confidential Exhibit 2.

Additionally, Duke has requested that the Commission approve ongoing review of Duke's implementation of its Phase 2 Compliance Plan. We find that Duke should report on its progress in conjunction with its semi-annual Rider 71 and 62 filings.

**C. <u>Clean Energy Project Approval</u>.** Ind. 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, such as flue gas desulfurization and selective catalytic reduction equipment. SCRs are explicitly within the definition of "clean energy projects." In fact, as Mr. Miller's testimony shows, all of the projects that Duke proposes to install as part of its Phase 2 Compliance Plan meet the definition of "clean energy projects," and therefore, qualify for the incentives under Ind. Code § 8-1-8.8-11. Further, Duke's testimony in this proceeding demonstrates the necessity and reasonableness of the projects.

Additionally, Mr. Miller's testimony establishes that the Phase 2 projects constitute clean coal technology. Clean coal technology, as defined by Ind. Code § 8-1-8.8-3, means a technology (including precombustion treatment of coal):

> (1) that is used in a new or existing energy generating facility and directly or indirectly reduces airborne emissions of sulfur, mercury, or nitrogen oxides or other regulated air emissions associated with the combustion or use of coal; and
>
> (2) that either:
>
> (A) was not in general commercial use at the same or greater scale in new or existing facilities in the United States at the time of enactment of the federal Clean Air Act Amendments of 1990 (P.L. 101-549); or
>
> (B) has been selected by the United States Department of Energy for funding under its innovative Clean Coal Technology program and is finally approved for such funding on or after the date of the enactment of the federal Clean Air Act Amendments of 1990 (P.L. 101-549).

Mr. Miller testified that SCRs, which directly reduce nitrogen oxide emissions and indirectly promote the reduction of mercury emissions, were not in general commercial use in the United States on large coal-fired facilities in 1989. He also explained that activated carbon injection in combination with either electrostatic precipitators or baghouses will directly reduce mercury emissions and was certainly not in general use prior to 1990. This technology has generally only been developed in the last ten years in response to the promulgation of the new mercury regulations. Similarly, Mr. Miller explained, the use of proprietary chemical additives in FGDs to mitigate the mercury re-emission phenomenon (and hence promote additional mercury capture) has only been investigated in earnest in the past couple of years. Duke Energy had previously conducted a study of a similar such chemical at its Zimmer Generating Station in southern Ohio in 2001, but the chemical formulations at that time failed to bring the re-emissions under control. The more recent chemical formulations have been successful. This technology was not in general use in 1989. Lastly, Mr. Miller testified, the use of $SO_3$ mitigation technology, in this instance of the dry sorbent injection type, will mitigate the formation of "blue plume" that can accompany the installation of an SCR on a unit that combusts high sulfur coals. The mitigation of $SO_3$ is also important when using ACI. The mercury capturing properties of activated carbon are inhibited by $SO_3$, mitigating the $SO_3$ concentrations in the flue gas will therefore improve the efficiency and sorbent utilization rates of the ACI, again promoting better capture of mercury.

We find that Duke's proposed equipment meets both applicable definitions of clean energy projects and clean coal technology. We further find that Duke should be authorized for certain financial incentives as provided for in Ind. Code § 8-1-8.8-11, in connection with Duke's proposed Phase 2 compliance plan, including: (1) the timely recovery of costs incurred during the construction and operation of the clean coal technology projects; (2) the timely recovery of Phase 2 and Phase 3 plan development, engineering and pre-construction costs; (3) and the use of accelerated depreciation. As noted by Mr. Freeman, this Commission has approved post-in-service carrying costs in prior environmental plan orders, including combined Cause Nos. 41744-S1 and 42061 and combined Cause Nos. 42622 and 42718. We agree with Mr. Freeman that Ind. Code § 8-1-8.8-12 provides for recovery of carrying costs, including during the operation of the environmental projects, and consistent with our prior orders, approve Duke's request for authority to defer post-in-service carrying costs on an interim basis until the applicable costs are reflected in Duke's retail rates.

Consequently, we approve Duke's request to recover the depreciation and O&M costs associated with its Phase 2 Environmental Compliance Plan, and for costs described above and in Petitioner's Exhibit I, through its existing Rider 71.

**D.** **CWIP/QPCP Approvals.** Duke requests that the Commission approve for use, pursuant to Ind. Code § 8-1-2-6.8 and 170 IAC 4-6-2, Duke's proposed Phase 2 emissions reduction equipment as QPCP. QPCP means an air pollution device on a coal burning energy generating facility or any equipment that constitutes clean coal technology that has been approved for used by the Commission and that meets applicable state or federal requirements. Ind. Code § 8-1-2-6.8.

We find that the proposed projects constitute QPCP, as defined in Ind. 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. We recognize that in *General Motors Corp. v. Indianapolis Power & Light Co.*, 654 N.E.2d 752 (Ind. Ct. App. 1995), the Indiana Court of Appeals declared that a portion of Ind. Code § 8-1-2-6.6 relating to Indiana coal violates the Commerce Clause of the United States Constitution. The Court severed the unconstitutional provision from the remainder of the statute, which was held to be valid and effective. Although we find that the proposed projects will allow Duke to continue the use of Indiana and Illinois Basin coal, in accordance with the *General Motors* case, we do not treat this factor as a prerequisite for Duke to receive a CPCN.

We further find that each proposed project constitutes an air pollution device, and meets the applicable requirements of 170 IAC 4-6, as described in the testimony of Mr. Miller.

Therefore, we approve Duke's request to recover its Phase 2 Compliance Plan projects and associated costs, as discussed above[2] and set forth in Duke's testimony in this proceeding, through its existing Rider 62.

A. **Confidentiality Findings.** Duke filed motions for protection of confidential and proprietary information on June 28, 2012, and December 7, 2012. In these Motions and attached affidavits, Duke demonstrated a need for confidential treatment for the following: (1) information related to financial, power, fuel, and emission allowance forecasts; (2) detailed compliance plan project costs, estimates, and schedules; (3) confidential IRP present value of revenue requirement information; (4) IRP modeling inputs; (5) actual and forecasted O&M and fuel costs; (6) inputs and outputs to Duke's engineering screening model; (7) configuration, operation and related emissions information, including testing data; (8) environmental compliance equipment and reagent testing data; and (9) environmental compliance alternatives reviewed by Duke, including capital and O&M estimates developed internally and by vendors. On July 10, 2012, and December 11, 2012, 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. Duke's Phase 2 Environmental Compliance Plan is approved, including the construction and use of various emission reduction technologies.

2. Duke's proposed Phase 2 equipment constitutes clean coal technology, clean energy projects and qualified pollution control property.

3. Duke is issued a Certificate of Public Convenience and Necessity for the proposed clean coal technology projects as described above. This Order constitutes the Certificate.

[2] Based on our discussion above, Duke must request and obtain a modification to its CPCN in order to recover any increase above the project cost amounts contained in its Confidential Exhibit 2 (excluding AFUDC).

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

5. Pursuant to Ind. Code § 8-1-2-6.8, the Commission approves the use of the proposed clean coal technology as qualified pollution control property.

6. Pursuant to Ind. Code § 8-1-8.7-4(b), the Commission approves Duke's cost estimates as described in this Order.

7. Duke's request for financial incentives in connection with Duke's Phase 2 compliance plan are approved as described above, specifically the timely recovery of costs incurred during the construction and operation of the clean coal technology projects; the timely recovery of Phase 2 and Phase 3 plan development, engineering and pre-construction costs; use of accelerated depreciation; and the authority to defer post-in-service carrying costs on an interim basis until the applicable costs are reflected in Duke's rates.

8. Duke's proposal for accelerated (20-year) depreciation for the Phase 2 Compliance Plan projects is approved.

9. The information filed by the Parties in this Cause pursuant to motions 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.

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

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

**APPROVED:** APR 03 2013

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

Brenda A. Howe

**Brenda A. Howe**
**Secretary to the Commission**