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STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

JOINT PETITION OF DUKE ENERGY INDIANA, INC., WABASH VALLEY POWER ASSOCIATION, INC., AND DUKE ENERGY VERMILLION II, LLC, WHEREBY:	)
DUKE ENERGY INDIANA, INC. REQUESTS, PURSUANT TO IND. CODE § 8-1-8.5-1 *ET SEQ.* (1) ISSUANCE OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY ("CPCN") FOR THE PURCHASE OF A PORTION OF THE VERMILLION GENERATING STATION FOR THE FURNISHING OF ELECTRIC UTILITY SERVICE TO INDIANA CUSTOMERS, OR ALTERNATIVELY, TO CONVERT COAL FIRED GENERATING FACILITIES TO GAS FIRED GENERATING FACILITIES FOR THE FURNISHING OF ELECTRIC UTILITY SERVICE TO THE PUBLIC AND FOR THE APPROVAL OF THE CONSTRUCTION AND COSTS OF SUCH FACILITIES; (2) AUTHORIZATION OF THE DEFERRAL FOR SUBSEQUENT RECOVERY OF POST-IN-SERVICE CARRYING COSTS, DEPRECIATION EXPENSE, AND TRANSACTION COSTS ASSOCIATED WITH THE FACILITIES FOR WHICH THE CPCN IS REQUESTED; (3) RECOVERY OF CAPITAL AND OPERATION AND MAINTENANCE (O&M) COSTS AND DEPRECIATION EXPENSE FOR THE DRY SORBENT INJECTION TECHNOLOGY FOR GALLAGHER GENERATING STATION UNITS 2 AND 4, FOR WHICH PETITIONER HAS RECEIVED A CPCN IN CAUSE NO. 43873, THROUGH STANDARD CONTRACT RIDER NOS. 62 AND 71 AND PURSUANT TO INDIANA CODE §8-1-8.8-1 *ET SEQ.,* INCLUDING INTERIM AUTHORIZATION OF THE DEFERRAL FOR SUBSEQUENT RECOVERY OF ASSOCIATED POST-IN-SERVICE CARRYING COSTS, DEPRECIATION AND O&M FOR THE DRY SORBENT INJECTION TECHNOLOGY UNTIL SUCH COSTS ARE REFLECTED IN RATES VIA STANDARD CONTRACT RIDER NOS. 62 AND 71; (4) TIMELY COST RECOVERY RELATED TO THE SURRENDER OF CERTAIN SULFUR DIOXIDE EMISSION ALLOWANCES THROUGH STANDARD CONTRACT RIDER NOS. 63 AND 70; (5) APPROVAL OF A REGULATORY ASSET WITH CARRYING COSTS FOR COSTS INCURRED TO PURSUE THE GALLAGHER GAS CONVERSION AND KEEP THAT OPTION OPEN THROUGH THE END OF 2011; AND (6) APPROVAL OF THE RECOVERY OF THE NET DEPRECIATED VALUE AND DISMANTLING COSTS OF GALLAGHER UNITS 1 AND 3 UPON	) CAUSE NO. 43956) APPROVED: DEC 28 2011

RETIREMENT, IF THE PURCHASE OF A PORTION OF VERMILLION GENERATING STATION IS APPROVED)
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)
WABASH VALLEY POWER ASSOCIATION, INC. REQUESTS, PURSUANT TO IND. CODE § 8-1-8.5 *ET SEQ.* AND IND. CODE § 8-1-2.5 *ET SEQ.*: (1) ISSUANCE OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY TO ACQUIRE AN INTEREST IN EXISTING GENERATING FACILITIES; AND (2) AS EVIDENCE OF INDEBTEDNESS PAYABLE AT PERIODS OF MORE THAN TWELVE MONTHS FOR PURPOSES OF FUNDING THE ACQUISITION)
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DUKE ENERGY VERMILLION II, LLC REQUESTS THAT THE COMMISSION CONFIRM ITS IND. CODE § 8-1-2.5 DECLINATION OF JURISDICTION OVER VERMILLION II'S OWNERSHIP OF THE VERMILLION COUNTY MERCHANT PLANT ("VERMILLION FACILITY") AND DECLINE JURISDICTION OVER APPROVING VERMILLION II'S PROPOSED TRANSFER OF THE VERMILLION FACILITY TO DUKE ENERGY INDIANA, INC. AND TO WABASH VALLEY POWER ASSOCIATION, OR TO THE EXTENT DEEMED NECESSARY, APPROVE VERMILLION II'S PROPOSED SALE AND TRANSFER OF THE VERMILLION FACILITY TO DUKE ENERGY INDIANA, INC. AND TO WABASH VALLEY POWER ASSOCIATION, INC., PURSUANT TO IND. CODE § 8-1-2-84, AND FIND THAT UPON SUCH SALE AND TRANSFER, VERMILLION II WILL NO LONGER BE DEEMED A PUBLIC UTILITY BY THE COMMISSION)

ORDER OF THE COMMISSION:

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

On September 28, 2010, Duke Energy Indiana, Inc. ("Duke Indiana" or "Company") filed a Petition with the Indiana Utility Regulatory Commission ("Commission") under this Cause number, requesting the issuance of a Certificate of Public Convenience and Necessity ("CPCN") pursuant to Ind. Code ch. 8-1-8.5 for the conversion of Gallagher Units 1 and 3 to natural gas, including approval of the estimated costs for the conversion and the construction of a gas pipeline. In addition, Duke Indiana requested approval of its proposed accounting and rate treatment related to the conversion, including deferral for subsequent recovery of depreciation and post-in-service carrying charges on the capital costs incurred until included in rates. Duke Indiana further requested recovery of the capital and operation and maintenance ("O&M") costs and depreciation expense associated with the installation of a dry sorbent injection ("DSI") System on Gallagher Units 2 and 4 through its Standard Contract Rider Nos. 62 and 71, as well as approval of Duke Indiana's proposed accounting and rate treatment related to deferral for subsequent recovery of O&M, depreciation, and post-in-service carrying charges on the capital costs incurred for the DSI System until included in rates. Finally, Duke Indiana requested recovery of the costs related to the surrender to the United States Environmental Protection Agency ("EPA") of certain sulfur dioxide ("SO_2") emission allowances ("EAs") through Standard Contract Rider No. 63.

Pursuant to notice, and as provided for in 170 IAC § 1-1.1-15, a Prehearing Conference was held on November 10, 2010. On November 18, 2010, the Commission issued a Prehearing Conference Order that established the original procedural schedule for this Cause. On December 14, 2010, Duke Indiana prefiled its case-in-chief testimony and non-confidential exhibits.

On January 4, 2011, after seeking permission from the Commission, Duke Indiana amended its Petition to include, as part of the cost recovery requested, recovery in rates of the book value of the non-native SO_2 EAs that it surrendered, or will surrender, as a result of the New Source Review ("NSR") Litigation May 29, 2009 Remedy Order or the Consent Decree through Duke Indiana's Standard Contract Rider No. 70 – Summer Reliability Adjustment ("Rider 70"). Duke Indiana also provided an update of the status of its appeal to the Seventh Circuit Court of Appeals of the May 29, 2009, NSR decision related to Wabash River Units 2, 3 and 5. Also on January 4, 2011, Duke Indiana filed its confidential exhibits and workpapers.

On February 17, 2011, Duke Indiana Industrial Group ("Industrial Group") filed a Petition to Intervene in this proceeding, which was subsequently granted by the Commission. On March 11, and May 26, 2011, Duke Indiana filed Supplemental Testimony.

Also on May 26, 2011, Wabash Valley Power Association, Inc. ("Wabash Valley") filed a Petition under Cause No. 44031, accompanied by its case-in-chief testimony and exhibits. The 44031 Petition requested, among other things, the issuance of a CPCN to purchase an additional 12.5% undivided interest in the Vermillion Generating Station. On May 27, 2011, Duke Energy Vermillion II, LLC ("Duke Vermillion'") filed a Petition in Cause No. 44032, accompanied by its case-in-chief testimony and exhibits. The 44032 Petition requested that the Commission confirm its declination of jurisdiction over the transfer of Duke Vermillion's interest in substantially all of the assets associated with the Vermillion Generating Station to Duke Indiana and Wabash Valley as tenants in common, or in the alternative to approve such transfer.

On May 31, 2011, Duke Indiana, Wabash Valley, and Duke Vermillion ("Joint Petitioners") filed separate motions to consolidate Cause Nos. 44031 and 44032 into Cause No. 43956. On June 22, 2011, Duke Indiana filed a Second Amended Petition for the purpose of revising its original request to include the issuance of a CPCN for the purchase of a portion of the Vermillion Generating Station, or alternatively, to convert the boilers for Gallagher Units 1 and 3 from coal-fired to natural-gas fired. In addition, Duke Indiana requested approval of accounting and rate treatment, including deferral for subsequent recovery of depreciation expense, post-in-service carrying charges on the capital costs incurred until included in rates, and transaction costs, related to the purchase of a portion of the Vermillion Generating Station or conversion of the Gallagher units. Duke Indiana also sought the approval of recovery through rates of the net depreciated value and dismantling costs for Gallagher Units 1 and 3 upon retirement and for approval of a regulatory asset with carrying costs for costs incurred through the end of 2011 to pursue the Gallagher gas conversion, should the Commission approve the purchase of a portion of the Vermillion Generating Station.

On June 30, 2011, the Commission consolidated Cause Nos. 44031 and 44032 into Cause No. 43956. The Commission also ordered Joint Petitioners to file an amended Joint Petition in Cause No. 43956, including a single caption reflecting the relief being requested by Joint Petitioners. On July 15, 2011, Joint Petitioners filed the required Joint Petition, requesting the relief discussed in paragraph 3 below.

On July 25, 2011, Wabash Valley filed its case-in-chief testimony with the Commission. Duke Vermillion filed its updated cover page and first page of its case-in-chief testimony, previously filed in Cause No. 44032, on July 27, 2011. On August 24, 2011, the Indiana Office of Utility Consumer Counselor ("OUCC") and Industrial Group filed their respective direct testimony. Duke Indiana filed its rebuttal testimony on September 15, 2011.

Pursuant to notice given and published as required by law, proof of which was incorporated into the record, an Evidentiary Hearing was held in this Cause on September 26, 2011, at 9:30 a.m. in Hearing Room 222, 101 West Washington Street, Indianapolis, Indiana. Duke Indiana, Wabash Valley, Duke Vermillion, the Industrial Group, and the OUCC appeared and participated at the hearing.

At the Evidentiary Hearing, Duke Indiana offered into evidence its case-in-chief testimony consisting of the testimony and exhibits of John J. Roebel, Jerry L. Golden, James E. Benning, Steven L. Pearl, Gary J. Hebbeler, Janice D. Hager, Dr. Richard G. Stevie, John P. Griffith, Diana L. Douglas, Keith B. Pike, and Kent K. Freeman. Duke Indiana also offered into evidence the supplemental testimony of Diana L. Douglas, Douglas F. Esamann, Diane L. Jenner, Janice D. Hager, John J. Roebel, Robert G. Presnak, John D. Swez, Edward F. Kirschner, and Kent K. Freeman. Finally, Duke Indiana offered into evidence the rebuttal testimony and exhibits of John J. Roebel, Steven L. Pearl, Dr. Richard D. Stevie, Keith B. Pike, Danny Wiles, and Kent K. Freeman.

Wabash Valley offered into evidence the direct testimony and exhibits of Rick D. Coons, Nisha A. Harke, Kathy A. Joyce, M. Keith Thompson, Gregory E. Wagoner, and Lee R. Wilmes.

Duke Vermillion offered into evidence the direct testimony and exhibits of Gregory H. Cecil.

The OUCC offered into evidence the direct testimony and exhibits of Anthony A. Alvarez, Cynthia M. Armstrong, and Wes R. Blakley.

The Industrial Group offered into evidence the direct testimony of James R. Dauphinais.

All evidence and exhibits were admitted into the record without objection.

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

1. **Notice and Jurisdiction.** Due, legal, and timely notice of the Evidentiary Hearing in this Cause was given as required by law. The Joint Petitioners are each a public utility within the meaning of that term as defined in Ind. Code § 8-1-8.5-1. Ind. Code § 8-1-8.5-2 requires a public utility to obtain a CPCN before beginning the construction, purchase or lease of any facility for the generation of electricity. Ind. Code § 8-1-2-84 also requires a public utility to obtain Commission approval for the sale of any of its property to another public utility. Accordingly, the Commission has jurisdiction over the Joint Petitioners and the subject matter of this proceeding.

2. **Joint Petitioners' Characteristics.**

A. **Duke Indiana.** Duke Indiana is a public utility corporation organized and existing under the laws of the State of Indiana with its principal office in the Town of Plainfield, Indiana, and is a second tier wholly-owned subsidiary of Duke Energy Corporation. Duke Indiana is engaged in rendering retail electric utility service in the State of Indiana and owns, operates, manages, and controls, among other things, plant and equipment within the State of Indiana used for the production, transmission, delivery, and furnishing of such service to the public.

B. **Wabash Valley.** Wabash Valley is a mutual benefit non-profit corporation organized and existing pursuant to the Indiana Non-Profit Corporation Act, with its principal place of business in Indianapolis, Indiana. Wabash Valley is a public utility corporation pursuant to the certification and authorization received in Cause No. 35091. Wabash Valley serves as a power supplier to its members and constructs, owns and operates generation, transmission and related plants and facilities.

C. **Duke Vermillion.** Duke Vermillion is a Delaware limited liability company, a subsidiary of Duke Energy Corporation, and an indirect subsidiary of Duke Energy Ohio, Inc. Duke Vermillion has its principal place of business in Cincinnati, Ohio. The Vermillion Facility is an eight unit natural-gas fired 640 megawatt merchant plant that is currently owned 75% by Duke Vermillion and 25% by Wabash Valley. The Vermillion Facility sells energy into the wholesale market, is subject to Federal Energy Regulatory Commission ("FERC") jurisdiction, and makes no retail electricity sales.

3. **Relief Requested in this Cause.** Pursuant to the Joint Petition filed in this proceeding, Joint Petitioners request the following:

A. **Duke Indiana:** (1) issuance of a CPCN pursuant to Ind. Code ch. 8-1-8.5 for the purchase of a portion of the Vermillion Facility or alternatively, to convert the boilers for Gallagher Units 1 and 3 from coal-fired to natural gas-fired boilers; (2) approval of accounting and rate treatment, including deferral for subsequent recovery of depreciation expense, post-in-service carrying charges on the capital costs incurred until included in rates, and transaction costs, related to the purchase of a portion of the Vermillion Facility or conversion of the Gallagher units to gas-fired units; (3) recovery of capital and O&M costs and depreciation expense for the dry sorbent injection ("DSI)" technology at Gallagher Units 2 and 4, for which Duke Indiana was granted a CPCN in Cause No. 43873, through Standard Contract Rider Nos.

62 and 71, and, in the interim, approval of accounting and rate treatment, including deferral for subsequent recovery of depreciation, O&M, and post-in-service carrying charges on capital costs, until included in rates; (4) cost recovery related to the surrender to the EPA of certain SO_2 EAs through Standard Contract Rider Nos. 63 and 70; (5) approval of a regulatory asset, with carrying costs, for Duke Indiana's costs incurred to pursue the conversion of the Gallagher units and keeping that option open through the end of 2011; and (6) approval of the recovery through rates of the net depreciated value and dismantling costs for Gallagher Units 1 and 3 upon retirement, should the Commission approve the purchase of a portion of the Vermillion Facility.

B. **Wabash Valley:** (1) issuance of a CPCN pursuant to Ind. Code ch. 8-1-8.5 for the purchase and acquisition of an additional 12.5% undivided interest, as tenants in common, in the Vermillion Facility currently owned as tenants in common by Wabash Valley and Duke Vermillion, a subsidiary of Duke Energy Ohio, Inc.; and (2) authority to execute notes as evidence of the indebtedness to fund the acquisition of the additional 12.5% undivided interest in the Vermillion Facility and to encumber its property to secure payment of that indebtedness.

C. **Duke Vermillion:** (1) declination of jurisdiction over Duke Vermillion's ownership interest in the Vermillion Facility, in accordance with Ind. Code ch. 8-1-2.5 and the Commission's order in Cause No. 43965; or to the extent deemed necessary, (2) approval of the sale and transfer of Duke Vermillion's ownership interest in substantially all of the assets associated with the Vermillion Facility to Duke Indiana and Wabash Valley, as tenants in common, and (3) find that upon such sale, Duke Vermillion will no longer be deemed a public utility by the Commission.

4. **Duke Indiana's Case-In-Chief.** Mr. Roebel originally testified that Duke Indiana sought approval of its proposal to convert Gallagher Units 1 and 3 to natural gas. Specifically, Duke Indiana sought a CPCN for the gas conversion project, including approval of estimated costs for the conversion and the construction of a gas pipeline, under Indiana's Powerplant Construction statute, Ind. Code ch. 8-1-8.5. Duke Indiana also requested that the Commission approve its proposed accounting and rate treatment related to the conversion of the Gallagher units to natural gas-fired units, including deferral for subsequent recovery of depreciation and post-in-service carrying charges on the capital costs incurred until included in rates. In addition, Duke Indiana requested recovery of capital and O&M costs and depreciation expense associated with the installation of the DSI System on Gallagher Units 2 and 4 through its Standard Contract Rider Nos. 62 and 71. Duke Indiana also requested that the Commission approve its proposed accounting and rate treatment related to deferral for subsequent recovery of O&M, depreciation, and post-in-service carrying charges on the capital costs incurred for the DSI System until included in rates. Finally, Mr. Roebel testified that the Company requested recovery of the costs related to the surrender of certain SO_2 EAs to the EPA through Standard Contract Rider Nos. 63 and 70.

A. **Overview of the Litigation and Underlying Projects.** Mr. Roebel noted that the present proceeding relates to NSR litigation brought against the Company[1] and other

[1] The NSR Litigation was originally brought against several plaintiffs, including PSI Energy, Inc., the predecessor of Duke Indiana. For the sake of simplicity, we will use the term "Company" to refer to the relevant

defendants in 1999 by the United States Department of Justice on behalf of the EPA. *U.S. v. Cinergy Corp.*, Cause No. 1:99-CV-1693 (S.D. Ind.). Mr. Roebel provided some background regarding the projects at the Wabash River and Gallagher Stations in an attempt to prove the reasonableness of the Company's actions in the NSR Litigation. Mr. Roebel testified that the underlying projects have been used and have proven useful for many years in supplying electricity to the Company's customers, and the Company's defense of the NSR Litigation depended heavily on its belief that the underlying projects were the type of routine maintenance, repair, and replacement typically exempt from NSR.

Mr. Roebel testified that the Company further believes that the reasonableness of its choice to litigate rather than to enter into a system-wide settlement is supported by the results achieved during the litigation. The EPA alleged NSR violations against the defendants for a total of 55 component replacement projects, each allegedly triggering NSR liability for SO_2, nitrogen oxide ("NO_X"), and particulate matter ("PM"). Therefore, the defendants faced potential liability for 165 total claims. Of the 165 total claims filed against the defendants, 102 claims were specific to the Company. The litigation strategy resulted in the defendants' exoneration on 163 of those claims. The Consent Decree signed as to the Gallagher pulverizer replacement projects resolves the liability finding on the remaining two of the 165 claims, while protecting the Company from future litigation regarding other component replacement projects at Gallagher Station.

Mr. Roebel testified that at the time the underlying projects were considered and constructed, the Company believed that they were operating within the industry's standard of routine maintenance, repair, and replacement, and the projects would not increase the plants' hourly emissions. The Company also believed that the projects did not rise to the level of reconstruction projects. Mr. Roebel stated that replacing the existing Gallagher pulverizers with refurbished ones to solve the opacity and derate issues was considered in the course of the routine maintenance, repair, and replacement that all power system operators constantly analyze and contemplate as part of the general upkeep of generating units. The pulverizer replacement projects provided EA savings associated with being able to burn lower sulfur fuels, and the Company expected a decrease in emissions with the new pulverizers. Based on Mr. Roebel's review of the economic analysis that occurred during the economic development of this project, he believes the pulverizer replacement was a reasonable and cost-effective option for customers.

Mr. Roebel provided additional background on the NSR litigation. From 1999 through 2000, the EPA filed a number of complaints and notices of violation against multiple utilities across the country for alleged violations of the NSR provisions of the Clean Air Act ("CAA"). The EPA alleged that projects performed at various coal-fired units were "major modifications", as defined in the CAA, and the utilities violated the CAA when they undertook those projects without obtaining permits and installing the best available emission controls for SO_2, NO_X, and PM. The complaints sought injunctive relief to require installation of pollution control technology and unspecified civil penalties in amounts of up to $32,500 per day for each violation. Generally, the utilities argued that the projects constituted routine maintenance, repair, and replacement activities that are exempt from NSR.

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party in the litigation, whether it was named PSI Energy, Inc. or Duke Indiana at the time. The term "Plaintiffs" refers to all parties to the litigation.

Mr. Roebel stated that companies throughout the industry watched the original EPA suits and settlements, and used information from those suits to inform their decision making. Mr. Roebel indicated that in December 2000 the defendants reached a non-binding agreement in principle with the EPA, which provided for the installation by 2004 of four scrubbers and four selective catalytic reduction units ("SCRs"), as well as the shutdown of 9 boilers, at an estimated cost of $1.4 billion. The agreement in principle was put on hold, however, and settlement talks did not resume again until January, 2003. When the settlement discussions resumed, the EPA requested that new settlement conditions be added to the agreement in principle, including additional equipment installations and performance standards for the pollution control equipment.

B. **<u>NSR District Court and Seventh Circuit Proceedings</u>.** Mr. Roebel next described the liability phase proceedings of the trial in the district court. All PM claims were dropped prior to trial, as were many of the NO_X claims. The jury returned a verdict in favor of the Company on all projects, except for four projects at Wabash River Station. The Wabash River projects for which the Company was found liable involved: (1) Unit 2 replacement of the front wall radiant superheater from June to July 1989; (2) Unit 2 replacement of the high temperature finishing superheater tubes and upper reheater tubing assemblies from May 1992 to September 1992; (3) Unit 3 replacement of the finishing, intermediate, and radiant superheater tubes and upper reheat tube bundles from June to October, 1989; and (4) Unit 5 replacement of the boiler pass and heat recovery actions from February to May, 1990.

Mr. Roebel explained that the parties and Court proceeded next to the remedy phase. The parties proposed alternative remedies to the Court in a trial in February, 2009. On May 29, 2009, the Court issued its Remedy Order and ordered the shutdown of Wabash River Units 2, 3, and 5 by September 30, 2009. *U.S. v. Cinergy Corp.,* 618 F. Supp. 2d 942 (S.D. Ind. 2009) ("Wabash River Remedy Order"). In addition, the Court ordered the Company to run Wabash River Units 2, 3, and 5 at a rate not to exceed the pre-project baseline emissions levels until such time as the units were shut down. The Court also ordered the Company to permanently surrender SO_2 EAs equal to the SO_2 emissions from Wabash River Units 2, 3, and 5 for the period May 22, 2008, (the date of the jury verdict) through the shutdown of the units on September 30, 2009. On September 30, 2009, Wabash River Units 2, 3, and 5 were placed on "inactive reserve" (i.e., the units are currently, but not permanently, shut down).

Mr. Roebel testified further that on December 17, 2009, the District Court granted the EPA's motion for a new trial. On May 19, 2009, the second jury returned a verdict in favor of the Duke Indiana on all projects except the two pulverizer replacement projects on Gallagher Units 1 and 3.

Mr. Roebel testified to his understanding of the then-current status of the Wabash River Remedy Order. The Duke Indiana appealed the Wabash River liability findings to the U.S. Court of Appeals for the Seventh Circuit. On October 12, 2010, the Seventh Circuit found in favor of the Duke Indiana on all counts, reversing the District Court's findings and the liability determination made by the jury on the basis of legal and evidentiary error. *U.S. v. Cinergy Corp.,* 623 F.3d 455 (7th Cir. 2010). At the time of Mr. Roebel's testimony, a petition for rehearing was pending in the Seventh Circuit, and the ultimate result of Duke Indiana's appeal was not finally determined.

Mr. Roebel testified that a proposed settlement (also referred to as the "Consent Decree") was filed by the parties with the District Court on December 22, 2009, and approved by the District Court on March 18, 2010. As part of the Consent Decree, the Company agreed to retire or convert Gallagher Units 1 and 3 to run on natural gas. The units can operate until they are either retired or converted to natural gas. If the Company decides to convert these units, the conversion must occur by December 31, 2012. If the Company elects to retire these units, the decision to do so must be made by January 1, 2012, and the retirement must occur by February 1, 2012. In addition, beginning January 30, 2011, and continuing thereafter until the units are converted or retired, the Company has agreed to operate Units 1 and 3 so that each unit achieves and maintains a 30-day rolling average emission rate for SO_2 of no greater than 1.70 lbs/mmBTU. The Company will also surrender SO_2 allowances during the conversion of Units 1 and 3 from coal to gas. In addition, the Company agreed to surrender permanently any SO_2 allowances for all of Gallagher Station that are unused at the end of any year. The Company also agreed to install and continuously operate a DSI system by January 1, 2011, on Gallagher Units 2 and 4, and thereafter achieve and maintain a 30-day rolling average emission rate for SO_2 of no greater than 0.800 lbs/mmBTU on these units.[2] The settlement further involves a contribution of \$6.25 million for other specified environmental projects (\$5 million of which will go toward environmental mitigation projects). One million dollars out of the \$6.25 million total would be shared with New York, New Jersey, and Connecticut to combat the effects of air pollution. In addition, the Consent Decree includes civil penalties of \$1.75 million to be paid by April 22, 2010.

Mr. Roebel testified that the Company did consider other alternatives prior to entering into the Consent Decree, including: (1) shutting down the Units; (2) converting the Units to natural gas; and (3) installing best available control technology for SO_2 in accordance with NSR requirements (likely wet flue gas desulfurization units ("FGDs"). After an economic and environmental analysis, the Company saw two reasonable options, retirement or conversion to natural gas, both of which were included in the Consent Decree. As described by Ms. Hager, Duke Indiana's integrated resource planning modeling for this cause indicated that conversion of the units would be a more cost-effective option for customers.

C. **Gallagher Gas Conversion.** Mr. Roebel next described the existing Gallagher Generating Station, and the conversions that would be required. Gallagher Station is located on the Ohio River in Floyd County near New Albany, Indiana, and was constructed in the late 1950s and early 1960s. The station consists of four nominal 150 MW gross coal-fired units with a station rated net capacity of 560 MW. After conversion, Gallagher Units 1 and 3 would no longer be capable of burning coal and would burn natural gas instead. Replacement of burners and igniters will be necessary, and the boiler casing will require additional bracing. The Consent Decree also requires the addition of a flue gas recirculation ("FGR") system, which will reduce NO_X emissions from the units. Mr. Roeble testified that detailed design will continue through the spring of 2011. A significant portion of the Gas Conversion Project involves

[2] A CPCN for a DSI System at Gallagher Units 2 and 4 was approved by the Commission in *Duke Energy Ind., Inc.*, Cause No. 43873, 2010 Ind. PUC LEXIS 309 (IURC Sept. 8, 2010).

installation of a 19.5 mile, high pressure, gas pipeline that will interconnect with a Texas Gas Transmission Company interstate pipeline on the Kentucky side of the Ohio River, as described by Mr. Gary Hebbeler.

Mr. Roebel further testified that due to their proposed conversion to natural gas firing, Gallagher Units 1 and 3 are considered at low risk for retirement due to impending environmental regulations. Preserving the capacity of these units now—before the pending regulations take effect—will benefit the Company and its customers. Mr. Roebel testified that, for all the reasons described, the conversion of Gallagher Units 1 and 3 from coal to natural gas is in the public interest.

Mr. Roebel testified that the overall estimate for the Gallagher Gas Conversion Project, including the natural gas pipeline, is approximately $71 million, which includes overheads, indirects, and a reasonable contingency amount given that the Project has not yet been bid. This amount does not include allowance for funds used during construction ("AFUDC") at this time: instead, the Company is requesting approval of its estimated project costs ($71 million), plus the actual, accrued amount of AFUDC. Mr. Roebel testified to his belief that the cost estimate was reasonable. He noted that it was compiled by experienced Duke Energy project engineers working together with Sargent & Lundy, LLC, and includes costs associated with gas burners, modifications to duct work and boiler structural supports for implosion, controls modifications, and safety modifications to meet current gas combustion codes. Mr. Roebel noted that the current cost estimate for the proposed 19.5 mile natural gas pipeline associated with the gas conversion project is approximately $39 million. Mr. Roebel testified that Duke Indiana generally expects that the O&M cost of the units would be comparable to the costs of other peaking units with low capacity factors (less than 10%). The operating cost will depend mostly upon the cost to obtain natural gas, and the projected operating costs of the converted units have been taken into account in the IRP modeling conducted by Ms. Hager and her team.

Mr. Roebel also testified regarding Duke Indiana's current construction timeline for the Gallagher Gas Conversion Project. Mr. Roebel testified that the construction timeline was reasonable in his opinion and that the Company has sufficient time under this schedule to have the Gallagher Units converted to run on natural gas and the pipeline completed to provide that gas within the time constraints of the Consent Decree.

D. DSI System Update. Mr. Roebel provided an update as to the Company's DSI System. On September 8, 2010, the Commission issued its final order in Cause No. 43873, in which it approved the use of the Company's proposed DSI System, granted the DSI System CPCN under Indiana Code ch. 8-1-8.7, found reasonable and approved the Company's cost estimate of $16.6 million, and found that the DSI System constitutes "clean coal technology" as defined in Ind. Code § 8-1-8.7-1. *Duke Energy Ind., Inc.*, 2010 Ind. PUC LEXIS 309. Mr. Roebel testified that the DSI System is fully constructed and operational. The Company anticipated being in compliance with the January 1, 2011, deadline in the Consent Decree.

Mr. Roebel noted that the Commission's Order in Cause No. 43873 left its determination on the DSI System cost recovery for a future proceeding. As such, the Company is seeking approval in this proceeding of recovery of the DSI System costs through its Standard Contract

Rider No. 62, Qualified Pollution Control Property Revenue Adjustment ("Rider No. 62"), and its Standard Contract Rider No. 71, Clean Coal Operating Cost Revenue Adjustment ("Rider No. 71"). Both are detailed in the testimony of Mr. Freeman.

Mr. Roebel testified that the Company is also seeking to recover O&M costs associated with the DSI System through its Rider No. 71 as provided for under Indiana law concerning qualified pollution control equipment, clean coal technology, and clean coal and energy projects. The Company estimates it will incur an incremental amount of O&M approximating $6.7 million annually, primarily for the costs of the reagent used in the DSI System. The cost of reagents, fuel, and EAs are all included in the total cost to dispatch the generating units. The cost of fuel and EAs has been traditionally subject to periodic adjustment clauses to ensure that actual costs are recovered. Mr. Roebel testified to the Company's belief that the O&M costs, particularly the variable reagent costs associated with this pollution control equipment, should be subject to a periodic adjustment clause providing for consistent rate recovery treatment for all variable dispatch costs. Such treatment was afforded to Duke Indiana's new scrubbers, which also remove SO_2, in *PSI Energy, Inc.*, Cause No. 42622/42718 (IURC May 24, 2006).

Mr. Roebel testified further that the $16.6 million figure described in his testimony and associated exhibits in Cause No. 43873 remained a reasonable estimate of the costs associated with the DSI System. The costs associated with implementing and using the DSI System are reasonable and compare favorably to retirement of the units. Conventional technologies could not achieve the SO_2 emission reductions as cost-effectively. The installation and use of the DSI System will increase the useful life of Gallagher Units 2 and 4, and results in a logical dispatching priority for the units. Mr. Roebel affirmed his belief that Duke Indiana's construction, implementation, and use of the DSI System is in the public interest.

E. <u>Industry Experience with Routine Maintenance Repair and Replacement</u>. Mr. Golden, a consultant and retiree from Tennessee Valley Authority, testified regarding the industry's experience with determining what types of projects constituted routine maintenance, repair and replacement (also sometimes referred to as "RMRR") for purposes of NSR requirements.

Based on his industry knowledge, experience, and review of information, Mr. Golden testified that the maintenance practices of utilities throughout the United States are remarkably similar. The passage of the Clean Air Act Amendments of 1977 and the implementation of regulations did not produce changes in either maintenance philosophy or practices. Mr. Golden confirmed that during the 1980s and 1990s, utilities understood that activities at a plant that cost more than 50% of the replacement value of the unit would require permitting action and that activities that would increase the capacity of a unit, as determined by its hourly emissions rate, might also have to undergo permitting action. Mr. Golden noted that state regulators also had the same understanding. Mr. Golden testified that, until 1999, the industry did not understand or anticipate that the EPA would claim that projects aimed at maintaining and improving the reliability and availability of a unit would be subject to NSR and permitting.

Mr. Golden testified further that when the EPA revised its NSR rule[3] in 1992, it reinforced utilities' opinions that as long as: (1) they were not performing maintenance, repair, and replacement activities that were similar in purpose, nature, and extent to the proposed Wisconsin Electric and Power Company ("WEPCo") projects; and (2) as long as the maintenance, repair, and replacement activities being performed were common in the industry, did not increase hourly emissions rates, and did not trigger the NSPS reconstruction provision, they could consider the activity to be routine maintenance, repair, and replacement that would not trigger NSR-related scrutiny. The industry continued to perform projects that would preserve the utility asset, preserve the availability and reliability of the unit, reduce operating and maintenance cost, ensure the safety of employees, and comply with all laws and regulations.

Mr. Golden testified that notices of violations were filed against a number of electric utilities in 1999 and 2000. Similar complaints were filed by some state regulators and private plaintiffs, as well as non-governmental organizations, such as the Sierra Club.

Mr. Golden noted that the reaction by industry participants to these enforcement actions has varied. He testified that although no utility has voluntarily conceded wrongdoing or violations of the CAA, some utilities have reached settlement with EPA to avoid the cost of litigation. Others have opposed the EPA's actions, with mixed results. Many utilities in the industry maintain the view that the enforcement initiative is not in accordance with the law or with the EPA's past actions, and they continue to maintain their plants as they have done historically. Mr. Golden observed the uncertainty within the industry as to whether the EPA would be successful with its enforcement initiative.

Based on his experiences with TVA during this period, Mr. Golden believed that it was reasonable for Duke Indiana to perform projects like those at Wabash River and Gallagher. Replacement of pulverizers and entire sections of boiler tubing, including replacement of superheaters and reheaters, had been commonly performed in the industry both before and after promulgation of the NSR regulations. The projects were economically justified, and in Mr. Golden's opinion, Duke Indiana had every reason to believe that the projects were routine maintenance, repair, and replacement for the electric utility industry that would not trigger NSR requirements.

F. <u>PSI's Refurbishment Projects</u>. Mr. Benning testified about PSI's program for maintaining its older generating units from the 1980s until his retirement in 1995. He explained that this program was known as a refurbishment program, a life extension program, or the Engineering Condition Assessment Program ("ECAP"). Through the ECAP program, PSI performed a thorough and detailed engineering analysis of its older generating stations to determine what would be necessary and economical in order to allow PSI to continue to operate these units reliably and efficiently and to defer the retirement dates of the units. Mr. Benning first described this program in his 1985 testimony before the Commission in Cause No. 37414. The Commission approved a settlement between PSI and the OUCC in that proceeding. PSI agreed to make quarterly progress reports to the Commission for its refurbishment projects, and

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[3] Requirements for Preparation, Adoption and Submittal of Implementation Plans; Approval and Promulgation of Implementation Plans; Standards of Performance for New Stationary Sources, 57 Fed. Reg. 32,314 (July 21, 1992) (codified at 40 C.F.R. pts. 51, 52, and 60).

did so until April 1989. It also agreed not to implement specific projects unless the long-term benefit exceeds the cost of the project.

Mr. Benning explained that the primary difference between the Company's ECAP program and typical maintenance programs is the detailed inspection and engineering analyses performed with respect to the generating units. The goal of PSI's normal maintenance program was to preserve normal operation of the generating units, while the goal of the ECAP was long range and intended to allow PSI to operate its units in a reliable and efficient manner over a longer period of time (approximately 20 years beyond the unit's originally-expected retirement date).

Mr. Benning testified that he reviewed documents associated with the Wabash River Projects. He concluded that all were performed as a part of PSI's ECAP. Each of these projects included the economic analyses performed on these projects. The analyses for all four of these projects demonstrated that the benefits would exceed the costs of the projects. Specifically, the estimated cost of the projects was less than the cost of replacement energy if the projects were not completed and the forced outage rates for the units were allowed to deteriorate. In no case did the estimated cost of any of these ECAP projects exceed 50% of the cost of replacement capacity.

Mr. Benning testified that in his opinion, it was reasonable for PSI to perform these projects on the Wabash River units. The analyses he reviewed clearly indicated a long-term benefit for customers. By extending the lives of Wabash River Units 1 through 5 and the four units at Gallagher, PSI's depreciation rates were reduced by about $4,800,000 per year to the benefit of customers. Further, by extending the lives of these units, PSI was able to defer adding additional capacity for a number of years. Other benefits resulted as well, including replacement of piping that potentially avoided a serious accident and improved combustion, which lowered opacity and emissions.

G. <u>PSI/Cinergy's Understanding of the NSR Requirements</u>. Mr. Pearl testified about PSI's, and later Cinergy's, understanding of the environmental requirements and limitations associated with the projects that PSI/Cinergy performed in the 1980s and 1990s that were the subject of the NSR Litigation. Mr. Pearl testified that he generally agreed with Mr. Golden's testimony describing the industry's knowledge of the development of the NSR regulatory framework, and found it consistent with his recollection of the Company's general knowledge and understanding over the past thirty-four years of his employment.

Mr. Pearl provided an overview of the evolution of the NSR and New Source Performance Standard ("NSPS") programs. Mr. Pearl testified that, based on the environmental department's understanding of the NSR regulations, as long as the capital projects were essentially like-kind replacements of original equipment that did not increase the hourly emissions of the generating unit, NSR requirements were not triggered. Like-kind replacements of existing equipment were not likely to increase the hourly emissions rate or reach the 50% replacement cost threshold (sometimes referred to as the "reconstruction" requirement under NSPS). Mr. Pearl also testified that he had reviewed the testimony Mr. Benning filed in Cause No. 37414 and the projects identified were not the type of projects to trigger NSR, NSPS, or

Prevention of Serious Deterioration ("PSD") regulations. He noted that Mr. Benning's testimony at the time indicated that the refurbishment costs would be $150 to $200 per kW, which would not have exceeded the 50% replacement cost threshold. He noted further that Mr. Benning described the objective of life extension as refurbishment to avoid future degradation of the units' availability and heat rate. Such refurbishment projects were widely considered to be the normal, like-kind replacements that would qualify as emissions neutral RMRR projects and would not trigger NSR or NSPS regulations.

Mr. Pearl testified that the environmental department was familiar with the EPA's determination regarding the WEPCo Life Extension Projects, and advised the power plant engineering and operations group about the WEPCo decision. He indicated that the environmental department did not conclude at the time that the PSI Life Extension Projects were also subject to the NSR and NSPS requirements because the EPA's decision made clear that the test to determine if a project constitutes RMRR is a fact specific, case-by-case determination. Mr. Pearl confirmed that the environmental department believed that NSR and NSPS would not be triggered as long as its units were well maintained with no permanent loss of capacity.

As to the specific Wabash River and Gallagher projects at issue, Mr. Pearl testified that the environmental department's role in the Wabash River project would not have been extensive. Tubed component replacements in boilers were extremely common and likely occurred at every unit outage. It was generally known and communicated throughout power plant engineering and operations that like-kind replacements of components were not known to trigger NSR-related issues. Mr. Pearl recalled that he was involved in considering NSR issues for Gallagher Station's pulverizer replacement projects. Replacement of the pulverizers was a larger project than the tubed component replacements at Wabash River, and Mr. Pearl was part of the team assembled to perform a comprehensive evaluation of the pulverizer replacement in 1997. At the time, Mr. Pearl advised that there were benefits to the Gallagher pulverizer replacements, such as a more consistent grind, thereby reducing some of the unburned carbon and loss on ignition issues that affected the station's opacity and particulate emissions, and increased its ability to grind lower sulfur fuel. Mr. Pearl noted that his role in the study phase for the project was to make sure the project team was aware of the triggers for NSR, such as increasing the capacity of the boilers to regain permanently lost capacity like the WEPCo units.

H. Proposed Gallagher Pipeline. Mr. Hebbeler testified about the natural gas pipeline required for the conversion of Gallagher Station Units 1 and 3 from coal-fired to natural gas-fired boilers, including the steps required to construct and permit a natural gas pipeline, the cost estimate, and the expected timeline.

Mr. Hebbeler confirmed that to support the conversion of Gallagher Units 1 and 3 to natural gas, Duke Indiana would need to install approximately 19.5 miles of pipeline to transport natural gas to Gallagher Station. The proposed pipeline would begin at a new interconnection with the Texas Gas Transmission, LLC interstate transmission pipeline near the city of Kosmosdale in Jefferson County, Kentucky. The pipeline would run west, under the Ohio River, to Harrison County, Indiana, and then turn north toward Gallagher Station and run parallel to the Ohio River, using existing utility and roadway corridors when possible. Mr. Hebbeler stated that the Company would also need to construct a new receiving station on the Gallagher Station property to serve as the terminus of the gas supply system. Upon completion of the pipeline, Duke Indiana will be able to deliver 5.6 million cubic feet of natural gas per hour ("MMcf/hr.") through a 20-inch diameter pipeline to Gallagher Station for its natural gas fuel needs. Because the proposed pipeline would be an interstate pipeline, Duke Indiana must obtain a certificate of public convenience and necessity from the FERC for the pipeline.

Mr. Hebbeler testified that Energy Management & Services Company, a pipeline consulting company, completed a gas supply system feasibility study for the project. The study identified two possible options: The first option was the 19.5-mile route described previously, and the second option was a 55-mile pipeline, beginning at an interconnection with the ANR Pipeline Company system located southwest of Mitchell, Indiana, and extending generally southeast to Gallagher Station. Due to identified terrain issues and the length (and associated cost) of the second option, Duke Indiana selected the 19.5-mile route.

Mr. Hebbeler noted that after determining this general route, Duke Indiana retained URS Corporation ("URS"), a cultural resource and environmental consultant, to complete an in-depth route selection analysis of this corridor, as required by the FERC. The URS analysis assisted the Company with selection of the route described herein through its analysis of factors such as ease of construction, population density, terrain, environmental constraints, and avoidance of potential cultural resource conflicts.

Mr. Hebbeler clarified that the proposed pipeline would be operated and maintained on behalf of Duke Indiana by Duke Energy Business Services LLC, a service company subsidiary of Duke Energy Corporation. Once the FERC issues, and Duke Indiana accepts, the certificate to construct and operate the Gallagher Station pipeline, Duke Indiana will become an interstate pipeline company. The Company has requested in its application to the FERC that the FERC waive its open access requirements for interstate pipelines, as the pipeline is intended to serve only Gallagher Station as a single-use pipeline. Mr. Hebbeler testified that Duke Indiana investigated other pipeline construction and ownership options, but determined that construction of the entire pipeline by Duke Indiana was projected to be the least cost option for customers, with benefits as to control over the management and schedule.

Mr. Hebbeler testified that Duke Indiana estimates the cost of the pipeline, excluding AFUDC, is approximately $39 million. The Company requested approval of its estimated project costs plus the actual, accrued amount of AFUDC, as discussed in the testimony of Mr. Kent Freeman. Mr. Hebbeler testified that, in his opinion, the cost estimate for the gas pipeline is reasonable. It was compiled by experienced gas pipeline engineers who worked on Duke Energy Ohio's other natural gas transmission pipelines and has been compared to the actual costs for these projects.

I. **IRP Modeling.** Ms. Hager testified about the updated integrated resource plan ("IRP") model runs that were performed concerning the economics of the proposed conversion of Gallagher Station Units 1 and 3 from coal to natural gas as compared to retiring the units. Ms. Hager explained that an IRP is a formal plan for meeting future utility load requirements, and is a utility's assessment of a variety of demand-side and supply-side resources to cost-effectively meet customer electricity service needs. She identified the steps of the IRP process.

Ms. Hager testified that in the 2009 IRP, the Company analyzed the options available for environmental compliance for several Duke Indiana generation plants, including Gallagher Station. It considered the various options for Gallagher Station and addressed what was then the proposed Consent Decree. The 2009 IRP included, for informational purposes only, an expansion plan that complies with the Consent Decree. The plan consists of switching all four Gallagher units to low sulfur fuel beginning in 2011, and converting Gallagher Units 1 and 3 to run on natural gas in 2013. The Consent Decree expansion plan also reflects advancing the addition of DSI controls for Gallagher Units 2 and 4 to 2011. The Company also updated the IRP analyses from the 2009 IRP to enable the Commission to be able to base its decision on the most accurate and up-to-date information available. Ms. Hager delineated in her testimony the specific changes made to reflect updated information that was not available for the 2009 IRP.

Ms. Hager testified further that she addressed the recent Seventh Circuit NSR Litigation decision by assuming that the Wabash River Units are removed from reserve shutdown status and placed in service effective January 1, 2011. Because of continuing uncertainty involving the operation of these units, however, she noted that the Company also performed a sensitivity on this assumption. Primarily due to mercury compliance requirements and SO_2 reductions associated with the CAIR replacement rule, Ms. Hager concluded that it is reasonable to assume the retirement of Wabash River Units 2, 3, and 5, beginning January 1, 2015.

Ms. Hager testified next about the Midwest ISO resource adequacy requirement, which requires that the loss of load expectation due to resource inadequacy cannot exceed one day in ten years (0.1 days per year). For Planning Year 2010/11, the applicable installed capacity reserve margin of 13.9% was used in the updated analyses.

Ms. Hager also explained that, each year, Duke Indiana develops a forecast of the fundamental market prices for key inputs such as natural gas, coal, EAs (including CO_2 allowances), and power prices. The Company used these updated forecast prices for natural gas and CO_2 allowances in the updated IRP analyses. The fundamental price forecast for natural gas decreased primarily due to newly-discovered domestic supplies of shale deposits. Ms. Hager noted that the lower price is not guaranteed because it depends on whether the ability exists to tap into the shale deposits without major impediments. Ms. Hager testified that the lower 2010 fundamental CO_2 allowance price forecast is largely due to projections of lower natural gas prices, projected increased coal retirements due to more stringent environmental regulation, lower loads, and increased projections of the ability to use international and domestic offsets to meet CO_2 reduction mandates. Ms. Hager further noted the uncertainly regarding the future regulation of CO_2 emissions.

Ms. Hager testified that the analyses to support this cause are based upon the analyses in support of the Edwardsport integrated gasification combined cycle ("IGCC") Project. Optimized resource portfolios were developed using the System Optimizer model, which assumes that the Edwardsport IGCC Project is completed in 2012. Furthermore, DSI systems are added, and low sulfur fuel is used at Gallagher Units 2 and 4, as required by the Consent Decree. Portfolios were developed both for a base level of energy efficiency and a high level of energy efficiency, as discussed by Dr. Stevie. Optimized resource portfolios (for both the base and high levels of energy efficiency) were also developed for the two options in the Consent Decree, assuming Gallagher Units 1 and 3 were retired effective February 1, 2012, and assuming Gallagher Units 1 and 3 were converted to natural gas effective January 1, 2013. The production cost model planning and risk assessment tool was used to perform a more detailed analysis of each portfolio, including subjecting the portfolios to sensitivities.

Ms. Hager noted the considerations required by the CPCN statute, Ind. Code § 8-1-8.5-4(2), prior to the Commission granting a CPCN, including conservation, load management, renewable energy, cogeneration, refurbishment, purchased power, interchange power, power pooling, and joint ownership. She provided detailed testimony as to how each of these considerations were reflected in the analysis.

Ms. Hager testified that, for all analyses, the portfolios based on the gas conversion project were more cost effective than the retirement option portfolios, as reflected in Duke Indiana's Confidential Ex. F-10. Ms. Hager noted that the IRP analyses conducted in this case yield results that are very close with less than 0.5% difference in the present value of revenue requirements between any options. Judgment is required to apply the results. Based on the analyses and on the qualitative considerations discussed by Mr. Roebel, Ms. Hager concluded at the time of her direct testimony that the gas conversion option was in the best interest of customers.

J. <u>Energy and Demand Forecast</u>. Dr. Stevie testified about Duke Indiana's long-term energy and demand forecast prepared in the summer of 2010 and provided a high level explanation of the methodology and considerations used to prepare such load forecast. Dr. Stevie presented a base forecast of energy efficiency impacts and a forecast of aggressive energy efficiency load reductions based on the energy efficiency goals set forth by the Commission in *Commission's Investigation, Pursuant to IC 8-1-2-58, into the Effectiveness of Demand Side Management Programs*, Cause No. 42693, 2009 Ind. PUC LEXIS 482 (IURC Dec. 9, 2009) ("Phase II Order"). Dr. Stevie also provided information on the underlying trends in the economy.

Dr. Stevie testified that the Load Forecast is developed in three steps: first, a service area economic forecast is obtained; next, an energy forecast is prepared; and finally, using the energy forecast, summer and winter peak demand forecasts are developed. Dr. Stevie explained that Moody's Economy.com prepares a forecast of key economic concepts specific to the service area of Duke Indiana with detailed projections of many aspects of the economy, including employment, income, wages, industrial production, inflation, prices, and population. This information serves as inputs into the energy models.

Dr. Stevie testified that the energy forecast is used to project the load required to serve: (1) Duke Indiana's three retail customer classes—residential, commercial, and industrial; (2) wholesale loads of municipals served directly by Duke Indiana; and (3) portions of the wholesale load requirements of the Indiana Municipal Power Agency ("IMPA") and Wabash Valley, as applicable. He further explained how those projections were calculated, testifying that variables are included in the forecast equations to account for factors such as number of customers, weather, and economic activity measures, such as employment, industrial production, income and price. The Company may adjust the forecast for anticipated increases in load due to a major new customer or a significant expansion at a current customer's site. Dr. Stevie further explained that the Company projects both a winter and a summer peak using econometric equations where peak demand is a function of economic growth, as measured by energy sales, and several key weather factors.

Dr. Stevie explained that, as a result of removing the Gibson 5 backstand obligation from the Duke Indiana load forecast, there is a reduction in the projected rate of growth in energy and peak demand. He opined that the projected growth rate in retail sales is more representative of the underlying rate of growth in energy use. For the period 2010 to 2020, the rate of growth in retail energy sales is projected at 1.4% before the impacts of energy efficiency programs are taken into account.

Dr. Stevie testified that he is familiar with the Indiana State Utility Forecast Group's ("SUFG") Biennial Load Forecast that was prepared in 2009 for the State of Indiana and the Duke Indiana service area. The 2009 SUFG forecast predicts that peak demand for the state will grow at 1.8% per year for the period 2010 to 2020, and the peak demand specific to the Duke Indiana service area will grow at 1.1% per year over the same time period.

Dr. Stevie further explained that after adjusting the SUFG forecast for differences in handling wholesale loads, the level of the Company's forecast is found to be below that of the SUFG, but the Company's projected growth rate for retail sales is slightly higher. The forecasted growth rate for Duke Indiana's retail energy sales is 1.4% for the period 2010 to 2020, slightly above the SUFG forecasted energy growth rate of 1.2%. Dr. Stevie further noted the Department of Energy's 2010 Energy Information Administration forecast has an energy growth rate of 1.2% per year for the nation, and 1.3% for the East North Central region, which includes Indiana.

Dr. Stevie also noted that historical demand side management ("DSM") programs that have been implemented in the Duke Indiana service area are already reflected in the summer 2010 load forecast. However, incremental DSM peak load reductions due to existing and future programs are not reflected in the historical data used to create the summer 2010 load forecast (or other load forecasts). For that reason, Dr. Stevie provided Ms. Hager with information on the incremental energy and peak load reductions for two cases: a base case as represented in the Company's 2009 IRP, and an aggressive case with energy efficiency load reductions based on the energy efficiency goals set forth by the Commission in its Phase II Order, in which the Commission established a goal of 2% annual cost-effective DSM savings within ten years for Duke Indiana and other utilities serving retail customers. This goal is phased in over the ten year period.

Dr. Stevie testified that the summer 2010 load forecast has not been reduced for the impact of load reductions due to the Company's interruptible contract customers. Rather, this load forecast portrays the level of expected internal peak demand. The projected summer peak load reduction from the interruptible customers based on the 2009 IRP is estimated to be

184.4 MW by 2020. Dr. Stevie testified that he provided the projected level of interruptible load reductions as well as the peak load reductions attributable to the PowerShare® CallOption program (181.9 MW) to Ms. Hager. Duke Indiana's summer 2010 load forecast has not been reduced for the peak load reductions that may occur through Duke Indiana's PowerShare® QuoteOption program. Dr. Stevie testified that due to the voluntary nature of this program, Duke Indiana cannot rely on these impacts for capacity planning purposes. In Dr. Stevie's opinion, Duke Indiana's summer 2010 load forecast was reasonable for planning purposes, and the methods used to create it are both reasonable and appropriate.

Dr. Stevie further offered testimony on the timing of an economic rebound. He testified that Moody's Economy.com. projected a rebound beginning mid-2009. Since mid-2009, a number of factors indicate the U.S. economy stopped its decline and began an upswing.

K. Management of Emission Allowances. Mr. Griffith testified about the management of Duke Indiana's SO_2 and NO_x EA positions, the current SO_2 and NO_x EA market, and how Duke Indiana participates in that market. He also testified to Duke Indiana's surrender of EAs pursuant to the Wabash River Remedy Order, the potential re-instatement of such EAs by the EPA, and the impact of the requirements to surrender EAs in the Consent Decree related to Gallagher Station.

Mr. Griffith stated that he is responsible for making sure that Duke Indiana is credited with sufficient SO_2 and NO_x EAs to meet the emissions compliance requirements for the current year and managing the forward years in the portfolios to meet future compliance needs, including the purchase of EAs, as needed, and the sale of EAs when Duke Indiana has a surplus. Mr. Griffith testified that in managing EAs, the goal is to approach a balanced position on an annual basis plus maintain a reserve of EAs for contingency. Furthermore, because EAs that do not have to be surrendered to the EPA are valid in later years, Duke Indiana also considers its position for years to come.

Mr. Griffith testified that the model distinguishes between native load EA requirements and EAs that support non-native sales. The Company currently manages the inventories separately, designating each EA purchase as native or non-native at the time of the transaction. EAs purchased for native load remain with native load; likewise with purchases made for non-native load. All zero cost allowances that Duke Indiana receives are maintained for the benefit of native load customers.

Mr. Griffith noted that Duke Indiana's current positions in SO_2, seasonal, and annual NO_x EAs are longer than would be required for compliance through the 2013 compliance period. This reflects concerns about environmental regulations and expectations of more restrictive future emissions requirements.

Mr. Griffith further testified to the effect of the NSR litigation. At the time of Mr. Griffith's testimony, uncertainty remained regarding the future of Wabash River Units 2, 3, and 5 because the plaintiffs in the NSR litigation asked for rehearing by the Seventh Circuit. Mr. Griffith testified that on February 26, 2010, Duke Indiana surrendered 21,395 additional SO_2 EAs for the native load portion of emissions from Wabash River Units 2, 3, and 5 based on emissions from May 22, 2008, through September 30, 2009, and 6,977 EAs for the non-native load portion. Mr. Griffith testified that, assuming the Seventh Circuit's decision overturning the district court stood, Duke Indiana would propose that the EPA and the Department of Justice reverse the February 26th allowance surrender by returning the surrendered allowances to Duke Indiana's account electronically.

Mr. Griffith also testified about the effect of the Gallagher Consent Decree on EAs. The Company agreed to surrender additional SO_2 EAs, in addition to the surrender required under existing law, based on the total tons of SO_2 emitted from Gallagher Station Units 1 and 3 from May 19, 2009, (the date of the jury verdict) through the date that Gallagher Units 1 and 3 are converted to run on natural gas or are retired pursuant to the Consent Decree. Beginning in calendar year 2010, Duke Indiana agreed to surrender any SO_2 EAs allocated to all of Gallagher Station (Units 1 through 4) that remain unused at the end of a particular year due to Duke Indiana emitting fewer tons of SO_2 than the allocated number of allowances. The surrender of allowances will also take into account any surrender ratio (currently two-for-one) under CAIR beginning in 2010.

Pursuant to the Consent Decree, Duke Indiana had already surrendered 7,299 additional SO_2 EAs for the native load portion of emissions from Gallagher Units 1 and 3 based on emissions from May 19, 2009 through December 31, 2009. The number of EAs surrendered for the non-native portion of emissions was 1,847. Additional surrenders will be made for emissions from these units in the future. The Company made these surrenders from Duke Indiana's native and non-native SO_2 EA inventories, respectively, and did not have to acquire additional EAs in order to make these EA surrenders because Duke Indiana's position for SO_2 EAs was long (and it remains long, based on projected emission rates through the 2013 compliance period).

Based on current assumptions about power prices and other matters, Mr. Griffith estimated that Duke Indiana will need to surrender sufficient additional SO_2 EAs to handle 5,652 tons of native load SO_2 emissions and 3,853 tons of non-native load emissions from Gallagher Units 1 and 3. No surrender of additional SO_2 EAs in 2010 pursuant to the Consent Decree will be needed in Mr. Griffith's opinion.

Mr. Griffith testified that Duke Indiana has also estimated future EA surrenders pursuant to the Consent Decree. Projection of future emissions depends on assumptions as to future power prices, the cost of and sulfur content of the fuel, and the efficiency of the pollution control equipment, including the DSI System.

L. <u>Economic Analysis of Environmental Options</u>. Mr. Pike testified to Duke Indiana's economic analysis of the claims brought by the plaintiffs in the NSR Litigation. The Company's first analysis estimated what the total costs could have been if the Company had installed the best available control technology ("BACT") for SO_2, NO_x, and PM at the time of each project for which the plaintiffs originally claimed Duke Indiana violated the NSR requirements of the CAA (the "BACT Case"). A second analysis approximates the costs of complying with the Wabash River Remedy Order and the costs of complying with the Gallagher Consent Decree (the "Reality Case"). Taken together, these analyses represent a high level assessment of the cost savings to customers due to Duke Indiana's actions and decisions regarding NSR compliance issues and the NSR litigation. The analyses cover 1982 through 2014, and all costs were converted to nominal dollars for comparison purposes.

Mr. Pike testified that the BACT Case analysis assumes that, at the time of the projects in the late 1980s and 1990s (pulverizer updates, boiler tube replacement, and other work), the Company would have instead installed the best available control technology. Thirty-two of the 34 projects challenged in the NSR Litigation were considered in the BACT Case analysis (the two projects at Wabash River Unit 1 were not considered due to the Wabash River Unit 1 IGCC conversions). The BACT Case analysis assumed that BACT controls would have been required for all three pollutants in the instance of any single project. For purposes of the BACT Case analysis, the Company had to identify what equipment and control technologies were available at the time of each of the projects to meet the CAA requirements. Such equipment and technology alternatives evolved with the passage of time.

Mr. Pike testified that the Company next estimated the capital costs as of the time of the assumed installations for the BACT equipment for each of the assumed NSR Projects. Cost estimates were based on Duke Indiana's experience with similar installations, as well as the reports of expert witnesses in the NSR Litigation. Other capital costs were also taken into account in the BACT Case Analysis. The Company accounted for the projected costs for the periodic replacement of the catalyst beds for the SCRs and the projected costs for landfill expansions to accommodate scrubber wastes over time.

The BACT Case Analysis also took into account the costs of derates and replacement energy resulting from the assumed installation of BACT Projects. The Company estimated the amount and value of lost capacity and energy it would have needed to replace as a result of the assumed BACT installations. The total derate amount was 97 MWs for all BACT projects. Mr. Pike explained that, with respect to replacement energy, the Company approximated the number of annual MWh lost for each unit based on the derate amount for each BACT control and the actual historical capacity factor of each unit. The Company then had to estimate the price for the replacement energy. After calculating the cost of components, the Company estimated an average replacement energy price for the system between \$14 and \$21 per MWh. Mr. Pike considered this a conservative estimate for the years prior to 2005.

Mr. Pike also noted that the BACT Case Analysis took into account changes in O&M costs resulting from assumed BACT projects. The BACT Case Analysis considered fuel cost savings resulting from the ability to use higher sulfur coal. He explained that when a scrubber is brought on line, the utility will generally switch to higher sulfur, lower priced coal. For purposes of the BACT Case analysis, the Company assumed that the Company would have switched high sulfur (5#/mmBTU SO_2) coal for each assumed scrubber, and that the price difference between the high sulfur coal and the lower sulfur coal that the unit actually used would be equal to the value of SO_2 EAs that would have been avoided between burning the lower sulfur coal and the higher sulfur coal without a scrubber. Mr. Pike asserted these estimates were conservative.

Mr. Pike then provided testimony as to the Reality Case Analysis. The purpose of the Reality Case Analysis was to assess the cost of the NSR Litigation remedy order involving the Wabash River Station Units and the Consent Decree involving the Gallagher Station Units. The steps of this exercise were similar to those involved in the BACT Case analysis. First, the Company estimated the capital costs required or avoided as a result of the Wabash River Remedy Order and the Gallagher Consent Decree. Second, the Company estimated the value of replacement capacity and energy related to the shutdown of Wabash River Units 2, 3, and 5. Third, the Company evaluated the additional O&M required or avoided due to the NSR. It also assessed the value of the EAs that had to be, or are projected to be, surrendered as a result of the NSR litigation outcomes. Finally, it reviewed and assessed the differences in fuel costs as a result of the NSR Litigation outcomes.

With respect to capital cost assessment, Mr. Pike testified that the Company compiled the cost estimates for the gas conversion on Gallagher Units 1 and 3, including construction of the pipeline, together with the capital costs of the DSI facilities on Units 2 and 4. The Gallagher Consent Decree also requires a $5 million expenditure for environmental mitigation projects. Finally, the capital cost total was reduced by certain avoided capital costs for Wabash River Units 2, 3, and 5, as well as Gallagher Units 1 and 3, due to the shutdown or anticipated reduced operation of these units.

Mr. Pike described the replacement capacity and energy assessment for the Reality Case. The Company estimated the value of replacement capacity needed to cope with the shutdown of Wabash River Units 2, 3, and 5 (265 MW) by calculating the cost of making capacity purchases from the Midwest ISO for 2010, 2011, and 2012. Capacity prices were based on Midwest ISO forward capacity prices. Based on the 2009 IRP, and given the addition of capacity for the Edwardsport IGCC plant in 2012, no capacity purchases were assumed to be required in 2013 or 2014. The Company also estimated the value of the energy that will have to be replaced because of the potential Wabash River unit shutdowns, and the anticipated reduced operations of Gallagher Units 1 and 3, assuming they would be running on natural gas.

Mr. Pike further described the Company's assessment of the potential change in ongoing O&M costs associated with converting Gallagher Units 1 and 3 to natural gas operation. Both maintenance and labor costs are expected to decrease with conversion to natural gas (after the transition is effected). The analysis also projects avoided fixed O&M as a result of the shutdown of Wabash River Units 2, 3, and 5. More fixed O&M was added for Gallagher Units 2 and 4 in connection with installing the dry sorbent injection.

Mr. Pike testified that with respect to variable O&M, the Reality Case includes a projection for the cost of the trona expected to be used in Gallagher Units 2 and 4, as well as a projection of additional disposal costs.

Mr. Pike further explained the adjustments and projections made in the Reality Case involving EAs. The Consent Decree will result in emission reductions due to the requirements to burn lower sulfur coal, install the DSI system, and convert Gallagher Units 1 and 3 to gas fired units. Pricing for the avoided EAs is based on Duke Energy's 2010 Fundamental Forecast. Mr. Pike noted that the Reality Case also takes into account the projected cost of EA surrenders required by the Wabash River Remedy Order and the Gallagher Consent Decree. Known and projected required surrenders were accounted for and valued.

Mr. Pike also testified to the evaluation of fuel costs included in the Reality Case analysis. Lower sulfur coal is generally higher priced than higher sulfur coal, and natural gas is more expensive per million Btu than coal. The Company assessed the projected difference in fuel costs as a result of switching to lower sulfur coal for all four Gallagher units, and then later switching to gas for Units 1 and 3. The increase in fuel costs per unit of fuel was, however, off-set by the need for less fuel resulting from the projected reduction in capacity factors for the Gallagher units.

Mr. Pike testified that the Company took certain future environmental projects in the 2009 IRP into account in the Reality Case. These contemplated environmental projects are installation of SCRs on Cayuga Units 1 and 2; installation of baghouses, activated carbon injection and DSI with lower sulfur coal on Wabash River Unit 6; and installation of activated carbon injection on Gallagher Units 2 and 4.

M. Estimated Rate Impact of Incremental Emission Allowance Costs. Ms. Douglas testified about the Company's proposal to recover incremental EA costs resulting from the resolution of the NSR claims against Duke Indiana, and the estimated rate impact to customers of the proposed cost recovery. She noted the EA surrender requirement as explained by Mr. Griffith. Ms. Douglas explained that the incremental costs she referred to are the Company's historical and future costs to comply with these additional SO_2 EA surrender requirements. Through October, 2010, the Company had incurred approximately $13.0 million in incremental EA costs, approximately $11.0 million of which were incurred in serving native load customers, and $2.0 million in serving non-native load customers. Approximately $7.8 million ($6.5 million of native load costs and $1.3 million of non-native load costs) of the total was related to the Wabash River Remedy Order, and approximately $5.2 million ($4.5 million of native load costs and $.7 million of non-native load costs) was related to the Gallagher Consent Decree.

Ms. Douglas testified that the incremental costs were determined using Duke Indiana's accounting books and records. Title 18 of the Code of Federal Regulations requires that issuances from a utility's EA inventory be accounted for using a monthly weighted average method of cost determination. Inventory is credited and expense is charged so that the cost of the EAs to be remitted (or surrendered) for the year is charged to expense monthly based on each month's emissions, even though EAs are not remitted until later. Therefore, the expense amount incurred through October, 2010, reflects expense for SO_2 EAs that were surrendered to the EPA in February, 2010, in addition to amounts recognized as expense based on the emissions that have occurred at the Gallagher units from January through October, 2010, (for which surrenders will be made to the EPA in February, 2011).

Ms. Douglas testified further that the reduction from inventory and corresponding expense accrual for the additional EA surrenders related to emissions from the Wabash River Units was recorded in September, 2009, using the weighted average cost of inventory at that time. The initial amounts related to Gallagher emissions under the Consent Decree were booked in December, 2009, upon the filing of the Consent Decree with the District Court, using the weighted average cost of inventory at that time. Subsequent inventory reductions and expense accruals were made during each month of 2010, using each month's applicable weighted average cost of inventory. Ms. Douglas testified that these monthly accruals will continue to occur, using the weighted average cost of inventory at the time of the accrual, as the Gallagher units operate and emit SO_2, which will require Additional EA Surrenders under the Consent Decree, or as true-ups to previously accrued tonnages become known.

Ms. Douglas explained next that determination of native and non-native load costs was made using Duke Indiana's accounting books and records. The Company maintains separate inventories for native and non-native EAs in accordance with an accounting authorization previously granted by the FERC to Duke Indiana (then known as PSI Energy, Inc).[4] Because each inventory is separately managed, they have different weighted average costs.

Ms. Douglas explained that the number of tons agreed to be surrendered under the Consent Decree was determined for each generating unit for each month based on emissions monitoring at the station. Native load customers receive the benefit of the lowest cost generating resources through a model that determines how much of the generation from each generating unit was used to serve native load and non-native load customers. The tons of SO_2 emitted for each generating unit are then allocated between native load and non-native load customers based on the allocation of generation by the model. Allocated tons are deducted from the applicable native or non-native inventory at that month's respective weighted average cost of inventory, and a corresponding amount of expense is accrued.

Ms. Douglas clarified that the Company will continue to incur incremental EA expense under the terms of the Gallagher Consent Decree. The same methodology will be used to determine future EA accruals and surrenders. Accounting personnel will make monthly accruals of expense and reductions in inventory to reflect the expense associated with the additional EAs that will be required to be surrendered at the end of each calendar year.

Ms. Douglas testified that the Company is proposing recovery of the incremental EA surrender expense under the same recovery mechanisms as are used to recover other EA costs, its Standard Contract Rider No. 63 - SO_2, NO_x, and Hg Emission Allowance Adjustment ("Rider 63") for the native portion of expense, and its Standard Contract Rider No. 70 -Reliability Adjustment ("Rider 70") for the non-native portion of the costs, used in the determination of non-native sales profits to be shared. As to the native load customers, the Company proposes to include the forecasted incremental EA surrender expense for the applicable forecast period in the calculation of the rate adjustment to be presented in the first Rider 63 proceeding following approval of this rate recovery proposal by the Commission in this proceeding. In addition, the Company proposes including actual costs for additional EA surrenders incurred cumulatively up through the last month of the reconciliation period covered by that proceeding. As to non-native load customers, the Company proposes including the incremental EA expense attributable to non-native load customers in the determination of non-native load profit sharing in the first Rider 70 filing following Commission approval of cost recovery in this proceeding.

Ms. Douglas testified that the annual retail rate impact, including the Wabash River Remedy Order costs, in 2012 is estimated to be an increase of 0.56% over 2009 retail revenues,

[4] The Company also maintains separate inventories by vintage, as specified in Title 18 of the Code of Federal Regulations.

with amounts in 2013 through 2015 declining from 0.04 % to 0.01%. Without the Wabash River Remedy Order costs, the 2012 rate impact is estimated to be 0.27% greater than 2009 retail revenues, with amounts in 2013 through 2015 declining from 0.03% to 0.01%.

In Ms. Douglas's opinion, cost recovery is appropriate because both "normal" EA expenses and incremental expenses are required as a result of governmentally mandated environmental programs. Customers have benefited from the low-cost generation at both the Wabash River and Gallagher Stations, and customers have been, and will be, better off in terms of the overall impact on their rates based on the Company's course of action in defending the NSR litigation and concluding the Consent Decree, even considering these incremental EA costs, as discussed in the testimony of Mr. Pike and Mr. Freeman. Ms. Douglas therefore reasoned that the costs have been incurred to ensure the continued low cost service to customers, and incremental expenses should be considered a recoverable operating cost, just like other EA expenses.

In supplemental testimony filed March 11, 2011, Ms. Douglas provided an update on the status of the Company's surrender of SO_2 EAs from Wabash River Units 2, 3, and 5 pursuant to the overturned Wabash River Remedy Order. Ms. Douglas testified that on March 3, 2011, the Company confirmed its receipt of the 28,372 EAs returned by the EPA. Therefore, the Company is no longer seeking cost recovery relating to the EAs surrendered pursuant to the Wabash River Remedy Order. The Company is seeking permission to recover through its existing tracking mechanisms, Rider 63 (for costs associated with native load generation) and Rider 70 (for costs associated with non-native load generation), the incremental SO_2 EA costs relating to Gallagher Station that it has incurred or will incur in accordance with the Consent Decree. Ms. Douglas explained that the Company will continue to incur costs beyond this planning period, but those estimates are not available currently.

N. Ratemaking Treatment for NSR Litigation Outcomes. Mr. Freeman testified about (1) the various costs that Duke Indiana expects to incur as a result of the gas conversion of Gallagher Station Units 1 and 3 from coal to natural gas; (2) the Company's proposed ratemaking treatment for the costs; (3) the Company's request for recovery of the costs related to the DSI System on Gallagher Station Units 2 and 4 via a rate recovery mechanism; (4) the Company's request for deferral of certain costs for both regulatory and accounting purposes for both the Gas Conversion Project and the DSI System; (5) the expected jurisdictional rate impacts from the recovery of Gas Conversion Project costs and for the DSI System; and (6) the Duke Indiana revenue requirements analysis performed under his supervision comparing the results of the economic analysis for the "BACT Case" with the "Reality Case," as explained by Mr. Pike.

Mr. Freeman testified that the Company is requesting authority from the Commission to accrue post-in-service carrying costs at rates equal to Duke Indiana's AFUDC rates on the jurisdictional portion of the capital expenditures for the Gas Conversion Project once the units are placed in service until the costs can be included in retail rates. The Company is requesting that the Commission approve the deferral for subsequent recovery of the jurisdictional portion of such costs and the depreciation expense associated with the capital projects using a regulatory asset account (FERC CFR account 182.3) until inclusion of such costs in retail rates. The

Company intends to include these deferred costs, and the original cost depreciated value of the capital expenditures in rates, in the next retail base rate case in which those assets are determined to be used and useful.

Mr. Freeman testified that AFUDC reflects the cost of funds used to finance a utility plant during the construction phase of a project. Such costs are recorded and capitalized as part of the total cost of the project. AFUDC is defined in the FERC Uniform System of Accounts, which includes instructions and a specific formula for calculating and determining the AFUDC rate. Duke Indiana was granted permission from the FERC on August 12, 1996, to determine its AFUDC rate on a monthly basis rather than the annual calculation specified by the Uniform System of Accounts instructions. It began calculating its AFUDC on a monthly basis in January, 1996. The Company proposes that its post-in-service carrying costs be accrued on the Gas Conversion Project capital expenditures at the Company's AFUDC rates once the projects are placed in service, including accrual on previously computed AFUDC or post-in-service carrying cost amounts, until such expenditures and post-in-service carrying costs begin earning a return in the Company's rates. Mr. Freeman confirmed that the accounting treatment proposed by the Company is in accordance with GAAP. He explained that Topic 980 of the Financial Accounting Standards Board's ("FASB") Accounting Standards Codification ("ASC") covers the accounting guidance for regulated operations formerly provided in Statement of Financial Accounting Standards ("SFAS") No. 71, and that costs associated with regulatory lag can be capitalized for accounting purposes, provided the provisions of ASC 980-340-25-1 are met.

Mr. Freeman further testified that deferral of the retail jurisdictional portion of the depreciation and post-in-service carrying costs on the capital costs related to the gas conversion project, until they can be included in rates, is appropriate from a ratemaking perspective. However, in order for the Company to defer the expenses and reflect the costs as a regulatory asset, it must be probable that such costs will be recovered through rates in future periods. In order to satisfy the probability standard, the Commission's order in this proceeding should specifically approve the accounting and ratemaking treatment proposed by Duke Indiana.

Mr. Freeman also summarized the rate impact of the gas conversion project. He noted that the rate impact depends on variables such as timing, the AFUDC rates, the rate of return, and final cost. However, based on the estimated gas conversion project cost and assuming a full year of depreciation expense, the peak year average retail rate impact is estimated to be 0.6% when compared to total retail revenues for the twelve months ended December 31, 2009.

Mr. Freeman further described the various DSI System costs Duke Indiana is requesting authority to recover. He testified that the DSI System generally would include the capital costs of the DSI System and incremental operating costs, including primarily the costs of reagent that would be injected into the flue gas stream. Mr. Freeman referenced Mr. Roebel's testimony as to the DSI System and its expected costs, which is described in more detail in Cause No. 43873.

Mr. Freeman testified that, consistent with the request for the Gas Conversion Project discussed above, the Company is requesting authority from the Commission to accrue post-in-service carrying costs at rates equal to Duke Indiana's AFUDC rates on the jurisdictional portion of the costs of the capital expenditures of the DSI System once they are placed in-service until the cost is included in retail rates. The Company is also requesting that the Commission approve the deferral for the subsequent recovery of such costs and the depreciation expense associated with the capital project using a regulatory asset account (FERC CFR account 182.3) until inclusion of such costs in retail rates takes place. Mr. Freeman noted that the Company requested and received a determination by the Commission in Cause No. 43873 that the DSI System constitutes "clean coal technology" pursuant to Ind. Code ch. 8-1-8.7. The Company is proposing that the capital expenditures associated with the DSI System be included in Rider 62. It also proposes that it receive construction work-in-progress ("CWIP") ratemaking treatment, and that its incremental operating costs, including reagent costs and depreciation of the capital project once they are placed in-service, be recovered in Rider 71.

Mr. Freeman explained that under CWIP ratemaking treatment, a utility is allowed to recover financing costs attributable to qualifying plant investments that are not included in the utility's "used and useful" rate base established in a general rate proceeding. Because financing costs under CWIP ratemaking are recovered as the costs are incurred and/or paid out, the utility is able to avoid the negative effects of regulatory lag, including negative cash flows and earnings erosion. The Company is proposing to commence CWIP ratemaking treatment (i.e., begin earning a cash return) on the DSI System project, via Rider 62, upon Commission approval of the project as a Qualified Pollution Control Property. Mr. Freeman clarified that the Company's accounting policies and procedures relating to CWIP ratemaking treatment are designed primarily to ensure that AFUDC is discontinued, as appropriate, when expenditures begin earning a cash return through the CWIP ratemaking treatment. CWIP ratemaking treatment under Rider 62 continues until the Commission determines such projects are used and useful in a proceeding that involves the establishment of the Company's base retail electric rates and charges, or until a project no longer satisfies the requirements of the CWIP rules.

Mr. Freeman observed that the company's clean coal operating cost revenue adjustment under Rider 71 was first approved by the Commission on November 25, 2003. Rider 71 provides for the recovery of incremental depreciation and O&M expenses incurred on qualified environmental projects in accordance with the provisions of Ind. Code ch. 8-1-8.8. The definition of clean coal and energy projects under Ind. Code § 8-1-8.8-2 includes advanced technologies that reduce regulated air emissions from existing energy generating plants that are fueled primarily by coal or gases from coal found in the geological formation known as the Illinois Basin.

Mr. Freeman explained that Rider 71 is designed to track and recover through Duke Indiana's retail electric rates actual depreciation and production O&M expenses on clean coal and energy projects such as the DSI System, and it is updated on a semi-annual basis using costs, which are subsequently reconciled to reflect actually incurred costs, with any differences between amounts billed to customers and actual amounts incurred being collected from or credited to customers.

Mr. Freeman summarized the rate impact of the DSI System. He noted that the rate impact depends on variables such as AFUDC rates, rate of return, final costs, and actual incremental O&M expense. However, based on the estimated capital cost of the DSI System, estimated O&M, and estimated AFUDC, and assuming a full year of depreciation expense, the peak year average retail rate impact is expected to be 0.4% when compared to total retail revenues for the twelve month period that ended December 31, 2009. After the DSI System is in service, and recovery is initiated under Rider 62 and Rider 71, the rate impact of Rider 62 will decline as the rate base declines with the addition of depreciation expense to the accumulated depreciation balance.

Mr. Freeman further testified that he prepared a high-level revenue requirement economic analysis consistent with the economic analyses sponsored by Mr. Pike. Starting with the results of Mr. Pike's analyses and adding actual capital expenditures and O&M expenses as discussed below, Mr. Freeman converted the costs into a present value revenue requirement ("PVRR") based on traditional rate case methodologies.

Mr. Freeman explained how the capital costs were converted into a revenue requirement. Estimated capital costs were treated the same as any asset and were thus depreciated. The accumulated depreciation reduced the original cost of the capital projects to the original cost depreciated value. This amount was multiplied by a revenue conversion factor based on the Commission's approved return levels in the Company's last three retail base rate cases applicable at the time of the capital addition or the closest order to that time, to determine the applicable revenue requirement. The retail demand allocator that was approved by the Commission in the Company's last three retail base rate cases was then applied to the projected total revenue requirement to determine the retail revenue requirement.

Mr. Freeman further explained that, consistent with the Company's integrated resource plan analysis, he utilized the after-tax weighted average cost of capital ("WACC") to convert the nominal dollars into 2010 dollars. He applied the after-tax WACC amount from the last retail base rate case, Cause No. 42359, to the yearly revenue requirements, and explained why this was an appropriate and conservative cost. Depreciation expense amounts were calculated by applying production depreciation rates from the last three retail base rate cases to the applicable original cost to calculate depreciation expense. For projects that meet the Ind. Code ch. 8-1-8.8 requirements, Mr. Freeman applied the depreciation rates approved for those filings.

For NOx, PM, and catalyst projects, Mr. Freeman testified that the Company used a depreciation rate of 6.67%, which was approved by the Commission in *PSI Energy, Inc.*, Cause No. 42411, 2003 Ind. PUC LEXIS 226 (IURC Nov. 25, 2003) and for SO_2 and landfill projects, the Company used a depreciation rate of 5.50%, as approved by the Commission in *PSI Energy, Inc.*, Cause No. 42622/42718.

Mr. Freeman testified further that the same general methodology was used to convert the depreciation expense into a revenue requirement. He applied a revenue conversion factor to the depreciation expense associated with the estimated projects, and then applied the retail demand allocator to determine the projected retail revenue requirement. Likewise, the O&M methodology was generally the same as the methodology used for depreciation expense using the same revenue conversion factor and retail demand allocator. However, for fuel and EA expense, the Company utilized an energy related retail allocator, which is consistent with the allocation of these costs in a retail base rate case. For capital, depreciation expense, and other O&M, the

Company used a demand related retail allocator. Mr. Freeman testified that he used the same methodology in the BACT case and the Reality Case to develop the revenue requirement.

Mr. Freeman testified that the total retail projected PVRR is $12.6 billion in 2010 dollars, and represents the total projected net present value cost had the Company installed the equipment required to meet BACT based on the government's original allegations of NSR violations.

The total retail projected PVRR for the Reality Case is $4.6 billion in 2010 dollars, and represents the total projected cost that the Company has incurred or will incur to meet the CAA requirements and the cost of the NSR Litigation. Mr. Freeman noted that both cases accounted for the full investments, notwithstanding the 2014 cutoff date for the Reality Case.

Mr. Freeman also testified to the compared costs. The projected cost to the Company's retail customers under the Reality Case is approximately $8 billion lower, in 2010 dollars, than the projected cost to the Company's retail customers had the Company conformed to the government's allegations of NSR compliance requirements for the generating projects in accordance with the BACT Case. When the Company accounts for further environmental projects, an additional $223 million would be included in the Reality Case. The projected net benefit to retail customers of the Reality Case, in comparison to the BACT Case, is approximately $7.7 billion. Mr. Freeman testified that this result demonstrates that the Company's customers benefited significantly from the Company's defense of the NSR Litigation.

5. <u>Duke Indiana's Supplemental Testimony</u>. Douglas F Esamann, President of Duke Indiana, Inc. provided an overview of Duke Indiana's proposed acquisition and joint ownership with Wabash Valley of the Vermillion Facility. He described the Vermillion Plant as essentially a sister station to Duke Indiana's Madison Station. Vermillion is connected to Duke Indiana's transmission system, and is located within the Midwest Independent System Operator ("Midwest ISO") footprint. He explained that as of May 1, 2011, Duke Vermillion, a wholly owned subsidiary of Duke Energy Ohio, Inc. and an affiliate of Duke Indiana, assumed ownership of 75% of each Vermillion unit with the remaining 25% interest owned by Wabash Valley. Mr. Esamann testified that Duke Indiana and Wabash Valley propose to purchase Duke Vermillion's undivided 75% ownership interest in the assets associated with the Plant, including real estate, inventory, materials and supplies, contracts and permits, with the final ownership shares of the entire Plant to be 62.5% for Duke Indiana and 37.5% for Wabash Valley (undivided ownership interest, as tenants in common). He testified that the transaction is structured as an asset purchase, with Duke Indiana and Wabash Valley being joint purchasers. He testified that upon closing of the purchase, the employees working on-site will become employees of Duke Indiana and will continue to operate the Plant. Mr. Esamann testified that approximately $245,000 in transaction-related costs, including outside attorney fees and engineering fees, will be incurred in connection with the acquisition for which Duke Indiana is requesting deferral and recovery.

Mr. Esamann explained how the opportunity to purchase a portion of the Vermillion Facility presented itself. He testified that Duke Energy Ohio approached Wabash Valley (among other parties) to see if there was an interest in purchasing the remaining share of the Plant. He stated that without Duke Energy Ohio's knowledge, Wabash Valley approached Duke Indiana and inquired whether it would be interested in a share of the Plant, as Wabash Valley did not have a need for the entire Plant. Mr. Esamann testified that Hoosier Energy also approached Duke Indiana after Hoosier was similarly approached by Duke Energy Ohio, however, Hoosier Energy later elected not to participate in the transaction due to timing considerations. He testified that Duke Indiana explained to Wabash Valley that it should independently negotiate with Duke Energy Ohio for the major terms of the deal (most importantly price), telling Duke Energy Ohio only that Wabash Valley was negotiating on behalf of an unnamed consortium, and not mentioning Duke Indiana. He stated that the ability to timely receive regulatory approvals would improve if the Company could demonstrate to regulators that the ultimate price for the Plant was arrived at during arms-length negotiations between unaffiliated parties. Mr. Esamann testified that he believed that Duke Energy Ohio had no knowledge of Duke Indiana's involvement as a potential purchaser at any point during its negotiations with Wabash Valley prior to the time the price was agreed upon, which was later confirmed by Duke Energy Ohio. Mr. Esamann stated that Duke Indiana took precautions internally so that Duke Energy Ohio would not learn of its potential interest.

Mr. Esamann testified that in addition to performing an IRP analyses of a break-even price to determine how the price ultimately arrived at by Wabash Valley and Duke Energy Ohio would compare with the Gallagher Gas Conversion, Duke Indiana also compared both the purchase price arrived at by Wabash Valley and Duke Energy Ohio and the Gallagher Gas Conversion cost to market prices, including comparing publicly available data on similar asset sales and a limited market solicitation of comparable peaking capacity from unaffiliated asset owners in the regional market. Mr. Esamann testified that the results of these analyses demonstrate that the Vermillion Plant is the best option to provide additional peaking capacity to Duke Indiana going forward, and compares favorably in price per kW to recent market purchases of peaking capacity. He stated that the independent competitive solicitation confirmed that the Vermillion price and the Gallagher conversion project price are both economic options, and that the IRP analyses demonstrated that the proposed Vermillion purchase is a more cost effective option and preferred over other options and in the place of the proposed Gallagher conversion. Mr. Esamann testified that on a $/kW basis the Gallagher gas conversion is approximately $263/kW compared to the Vermillion purchase at $170/kW. He stated that the Gallagher conversion remains a relatively low cost capacity option, however, and is less expensive than the bids received in the market solicitation. He testified that based on a review of expected reserve margins, at this time under base conditions, there is not a need for both the Vermillion Plant and the Gallagher Gas Conversion in the near term; however, given the potential of more retirements due to pending draft environmental regulations and the low price per kW for the Gas Conversion, inclusion of both projects could make sense even if it results in a surplus reserve margin for a few years. Mr. Esamann testified that at the end of April 2011, upon determining that the Vermillion Plant was a cost effective and preferred option to meet customers peaking electric needs and obtaining the required internal approvals to move forward, Duke Indiana allowed Wabash Valley to inform Duke Energy Ohio that it was the other party on whose behalf Wabash Valley had been negotiating. He stated that the parties then moved forward with conducting due diligence and negotiating a purchase agreement, which was executed on May 23, 2011.

Mr. Esamann testified that in the event the required Commission and FERC approvals are not obtained in the timeframe needed for the Vermillion Plant purchase, the Company requests the Commission to approve the Gallagher Gas Conversion Project as an alternative request. He asserted that under the Consent Decree the Company needs to be in a position to determine whether it is going to pursue the Gallagher Gas Conversion Project by January 1, 2012.

Mr. Esamann testified that with the addition of the Vermillion Plant as a peaking resource, Duke Indiana is replacing older coal fired units with newer natural gas-fired peaking capacity, which further diversifies its resource mix. In addition, he stated that Vermillion is located within Duke Indiana's service territory and interconnected with its transmission system, and is fully deliverable to its load. Mr. Esamann testified that in addition to increasing fuel diversity, the purchase helps balance the Company's need for baseload, intermediate and peaking options. He stated that the IRP demonstrates that the addition of a portion of the Vermillion Plant to the resource portfolio that includes the addition of the Edwardsport IGCC Project and the anticipated retirement of units is optimal for meeting customers' energy needs.

Mr. Esamann testified that without approval of Duke Indiana's requested deferral and subsequent recovery of costs, the Company would experience material earnings erosion, up to as much as $60 million in 2012, which would come in the midst of a large construction program. He explained that given the magnitude of Duke Indiana's financing requirements over the next several years, it is critical that the Company be in a position to attract capital on a timely and reasonable basis. He stated that approval of Duke Indiana's ratemaking and accounting proposals will help assure that the Company meets necessary debt coverage levels and other credit measures that will allow it to attract the necessary capital at reasonable costs, which will ultimately benefit both the Company and its customers.

Mr. Esamann testified that the Vermillion purchase is a reasonable, cost effective addition to the Duke Indiana system. He further testified that the Company has demonstrated the benefits and reasonableness of the Gallagher Gas Conversion Project as a fall back option, should the Vermillion purchase not obtain regulatory approval. He stated that it is reasonable for the Company to continue to keep the Gallagher option viable and to request recovery of the costs spent to date and expected to be spent for the remainder of the year, as an option cost. Mr. Esamann testified that Duke Indiana has agreed to cap the amount of this option cost to be deferred and subsequently recovered from customers at today's estimate of $6.2 million plus actual accrued carrying cost. Mr. Esamann quantified Duke Indiana's requested relief stating that the estimated amounts would be trued up to actual costs prior to recovery from customers.

Mr. Esamann testified that Duke Indiana has the financial ability to purchase a portion of the Vermillion Plant and currently has a strong balance sheet and solid investment-grade credit ratings. He further testified that the acquisition is expected to be partially funded from internal cash generation, issuances of debt and equity. He stated that equity funding requirements, to the extent they are required to maintain an appropriate capital structure for Duke Indiana, may be satisfied through either a reduction in dividends that the Company pays to its parent, Cinergy or through the receipt of equity contributions from its parent.

Mr. Esamann testified that the approval of a CPCN for the purchase of a portion of the Vermillion Plant is in the public interest. He stated that it compares favorably with alternatives, and the Company's IRP analyses demonstrated a need for the purchase. He testified that if Duke Indiana is not able to purchase the Vermillion Plant, it has demonstrated that the Gallagher Conversion is a needed project that would provide a cost effective capacity option for customers. It would also extend the life of the Gallagher units, diversify fuel use, and provide a low cost capacity option.

Diane L. Jenner, Director, Regulatory Strategy of Duke Energy Business Services LLC, described the Vermillion Plant as a natural gas-fired, simple cycle peaking plant consisting of eight GE Frame 7EA, single fuel gas combustion turbines ("CTs" or "units"), with a total capacity (nominal rating) of 640 MW (80 MW/unit), total summer rated capacity of 568 MW (71 MW/unit), and total winter rated capacity of 712 MW (89 MW/unit). She testified that the Commercial Operation Date of the Plant was June, 2000, and the Plant has been available as a peaking resource since that time. She stated that the eight turbine packages are identical in structure, and the Plant is basically identical to Duke Indiana's Madison Station. Ms. Jenner provided the confidential full load heat rate and equivalent availability factor of the Plant. She also stated that the units utilize dry low NOx burners for NOx control, the station is connected to Duke Indiana's transmission system within Midwest ISO, and has natural gas interconnections with Midwestern Pipeline Company and Panhandle Eastern Pipeline Company.

Ms. Jenner testified that Duke Indiana and Wabash Valley propose to acquire 83.3% and 16.7% respectively, of Duke Vermillion's 75% undivided ownership interest in the assets associated with the Plant, including real estate, inventory, materials and supplies, contracts and permits. She stated that the final undivided ownership share of the entire Plant will be 62.5% for Duke Indiana and 37.5% for Wabash Valley (undivided ownership shares). Ms. Jenner provided that Facility Interest Purchase Agreement, as Duke Indiana's Exhibit N-1, and stated that the agreement represents typical commercial provisions for a sale between co-owners. Ms. Jenner testified Duke Indiana's share of the transaction price of $170/kW (based on nominal rating) is $68 million and compares favorably with the $73 million estimated cost of the Gallagher Gas Conversion.

Ms. Jenner testified that in addition to the IRP analysis, comparable asset sales data from the industry and bids received in a solicitation process by an independent consult also support the reasonableness of the price/cost of the Vermillion Plant. In addition, she stated that the Company retained the engineering firm of Sargent & Lundy to prepare independent due diligence reports regarding the engineering and operational quality of the Plant.

As to operation of the Vermillion Plant, Ms. Jenner testified that it will continue to be operated by Duke Energy personnel, although the subsidiary that employs them will change. She also stated that it will continue to be offered into the Midwest ISO market and will be a registered Designated Network Resource (DNR), so Duke Indiana and Wabash Valley will be able to count the capacity toward respective Midwest ISO Resource Adequacy Requirements. Ms. Jenner explained that upon receiving the required regulatory approvals for the purchase of a portion of the Vermillion Plant, Gallagher Units 1 and 3 would be retired. She stated that if such regulatory approvals are not received, Duke Indiana is requesting the issuance of a CPCN for the Gallagher Gas Conversion Project.

Ms. Jenner explained how Duke Indiana determined whether the price for the acquisition of Vermillion was reasonable. First, she stated that Duke Indiana compared the negotiated price to other recent simple cycle CT acquisitions that have been discussed in the trade press. She testified that each of these prices was higher than the price of Vermillion on a $/kW basis. In addition, she noted that there is a very limited universe of assets that mimic the characteristics of the Vermillion Plant and most are not interconnected to the Company's transmission system, which diminishes the value to Duke Indiana due to transmission constraint risks and costs. As a result, the Company looked to ranges of comparable sales data to validate the reasonableness of the price of these assets. After review of the available comparable sales data, Ms. Jenner testified that she is confident the price being paid for this peaking asset is lower than prices paid for other like assets in the market.

Second, Ms. Jenner explained that Duke Indiana compared the negotiated price to the publicly available book value of the plant that was reported in Duke Energy Ohio's 10-K, which was $128 million for the production plant only. Ms. Jenner testified that this equates to $267/kW for 480 MW (nominal rating).

Ms. Jenner also explained that the Company retained The Brattle Group ("Brattle") to act as an Independent Administrator to conduct a solicitation for the purchase of other units that might be available to the Company. Brattle is a well known economic consulting firm that has conducted this type of solicitation in the past for other utilities but has not done any work for Duke Indiana in the past few years. She stated that the parties selected by Brattle consisted of nine holding companies with about 7100 MW of eligible CT capacity that met Brattle's criteria.

Ms. Jenner testified that if a bid from the solicitation was received for a superior asset at a comparable price or a bid for a similar asset at a lower price, Duke Indiana had every intention of pursuing that asset instead of either Vermillion or the Gallagher Gas Conversion project. Ms. Jenner testified that by March 25, 2011, Brattle had received two expressions of interest.

Ms. Jenner testified that Duke Indiana analyzed the information that was provided in the bid materials and compared the characteristics of the facilities bid to the Vermillion Plant, to the extent possible. She stated that at the time the analysis was performed, Duke Indiana's identity as a potential participant in the Vermillion transaction was not known to Duke Energy Ohio, so the Company could not gather the Vermillion-specific information from Duke Energy Ohio. Ms. Jenner explained that the Company used publicly available information for Vermillion, when available, and Duke Indiana's Madison plant as a proxy due to the similarity of the two plants. Ms. Jenner testified that the Company's analysis determined that the characteristics of the plants bid were not superior to the characteristics of Vermillion (or Madison as a proxy), and the prices substantially exceeded the Vermillion price, even before applying any kind of locational adjustment factor provided by Brattle. Ms. Jenner testified that on April 21, 2011, Duke Indiana formally declined the bid advising the bidder that its indicative price was not competitive with other generation alternatives available to the Company. Ms. Jenner testified that the prices bid were also higher than the estimated cost of the Gallagher Gas Conversion Project. Ms. Jenner testified that Duke Indiana conducted due diligence concerning the Vermillion Plant and found no significant issues with regard to the acquisition of a portion of the Vermillion Plant by the Company.

Ms. Janice D. Hager testified that analyses were performed to calculate a break-even price for the purchase of 400 MWs (nominal value) of the Vermillion Plant, using the IRP model runs developed for the analysis of the Gallagher conversion project. She explained that she calculated the difference in Present Value of Revenue Requirement (PVRR) between portfolios with and without the Vermillion capacity. She stated that if the Company could secure the Vermillion capacity at less than that difference in PVRR, customers would benefit. Ms. Hager explained the modeling process and testified that the breakeven analyses indicated that Duke Indiana could pay up to \$117/kW for 240 MWs, \$188/kW for 320 MWs, and \$245/kW for 400 MWs. She stated that the breakeven price increases as the MWs increase because Duke Indiana has a continuing need for capacity and the Vermillion capacity will be displacing new, more expensive peaking capacity in addition to the converted Gallagher capacity. Ms. Hager concluded that the negotiated purchase price of \$170/kW for 400 MWs was clearly well below the breakeven price calculated for the capacity and that new peaking capacity prices were higher than both the Vermillion capacity cost and the costs to convert Gallagher Units 1 and 3 on a \$/kW basis.

Ms. Hager testified that after Duke Energy management concluded that a purchase of 400 MWs of the Vermillion plant would be the best option based on the purchase price as compared to the breakeven price, additional analyses was performed to compare the proposed purchase of 400 MWs of the Vermillion capacity to the proposed conversion of Gallagher Units 1 and 3. Ms. Hager explained that as with the prior analyses, all portfolios included the completion of the Edwardsport IGCC Project in 2012 and the retirement of Wabash River Units 2 through 5 in 2015; however sensitivities assuming retirement of Wabash River Unit 6 in 2015 were also included. She stated that they also ran high energy efficiency, high natural gas prices, and high load and low load (plus and minus 5%) sensitivities.

Ms. Hager testified that an assumed price of \$68,000,000 for the 400 MWs of Vermillion capacity was used in the analyses. In addition, she noted that the estimated \$400,000 present worth revenue requirement for the advancement of transmission upgrades that may be required due to the assumed retirement of Gallagher Units 1 and 3 was also included in the analyses, but the \$245,000 of transaction costs were not. Ms. Hager testified that for the Gallagher conversion option, the cost was reduced by the estimated "sunk" costs of \$4,477,748. Ms. Hager concluded that her analyses demonstrated that the purchase of the Vermillion capacity is expected to be beneficial to customers and is the preferred option in the base case and in all sensitivity analyses. Ms. Hager also concluded that the capacity provided by the purchase of a portion of the Vermillion Plant is needed to meet the capacity needs of Duke Indiana customers.

Ms. Hager testified that Duke Indiana considered in its analyses conservation and load management, renewable energy resources, cogeneration, refurbishment of existing facilities, and the purchase of power. She also noted that interchange power and power pooling are not viable alternatives to the new capacity in Duke Indiana's plan. She stated that Joint ownership was considered and is being proposed in this proceeding. In summary, Ms. Hager concluded that based upon her analyses, the purchase of approximately 63% (400 MWs) of the Vermillion Plant will be a cost effective capacity addition for Duke Indiana customers and will provide needed capacity and energy over the long term.

Mr. John Roebel provided testimony regarding the technical due diligence performed by Duke Indiana on the Vermillion Plant. He explained that the Company utilized substantially the same due diligence process as it has used in the past when considering other asset purchases. He noted that the primary technical considerations for the Vermillion Plant were forced outages, inspection records, and maintenance practices. Mr. Roebel testified that the Company engaged Sargent & Lundy ("S&L") to assist with the technical assessment in order to obtain an unrelated party's perspective on the Plant. He stated that S&L toured the site, examined the Plant, checked for code violations, performed a safety review, and reviewed decommissioning costs for the site. Mr. Roebel provided a summary of Duke Indiana's Technical Assessment. Mr. Roebel stated that the current permits allow the units to operate approximately 2000 hours annually at full load, which would be adequate as long as the units continue to be used as peaking plants. He noted that the Vermillion Plant is basically identical to the Company's Madison Plant, which Duke Indiana has operated efficiently and safely for over eight years.

Mr. Roebel discussed the Company's actions taken to keep the Gallagher Gas Conversion as a viable "Plan B" under the timelines set forth in the Consent Decree. He testified that Duke Indiana is continuing to develop a detailed bid specification for burners and flue gas recirculation fans and will send out a request for proposal to potential burner companies once the specification is complete. He testified that S&L and Riley Power are continuing to complete detailed design work, with all design engineering for the plant conversions and material specifications complete by December. In addition, he stated that the labor specification will be issued for bid and the burner contract issued for fabrication by January, 2012. Mr. Roebel explained that by continuing engineering design in 2011, Duke Indiana will be poised to begin contract awards for both material and labor in early 2012 and will maintain the conversion schedule consistent with the Consent Decree requirements. Mr. Roebel testified that Duke Indiana has spent $4,477,748, not including AFUDC, through the end of April, 2011 on its efforts to keep the Gallagher Gas Conversion in a position to be completed in compliance with the Consent Decree. He stated that the Company expects to spend a total of approximately $6.2 million through 2011 to preserve the option for customers. Mr. Roebel testified that the Company continues to view the Gallagher Gas Conversion as a potentially valuable asset for customers. He stated that if the Vermillion opportunity had not presented itself, Duke Indiana would be continuing with the Gas Conversion. Mr. Roebel testified that the proposed Gallagher Gas Conversion continues to represent a relatively low cost form of generating capacity that would reduce environmental emissions, make use of existing infrastructure, and position the Company well for continuing to meet its obligation to provide reliable, cost-effective electric service in the future.

Mr. Robert G. Presnak, Senior Vice President of S&L provided the results of S&L's Independent Engineering Assessment, Review and Technical Evaluation of the Vermillion Facility. He stated that S&L reviewed data supplied by Duke Indiana and conducted a site walk down of the Vermillion Facility in May of 2011. Mr. Presnak testified that the overall condition of the Vermillion Facility is very good and that it has recorded very good equivalent availability factors and low equivalent forced outage rates, which surpass peer group performances. He concluded that the Vermillion Facility is fully capable of providing long term, reliable service as a simple cycle peaking power facility if it continues to be properly operated and maintained in accordance with good utility practice.

Mr. John D. Swez, Director, Bulk Power Marketing and Trading, Duke Energy Business Services LLC, provided testimony regarding how the Vermillion Plant, if purchased by Duke Indiana, would fit within the Duke Indiana portfolio from a dispatch / Midwest ISO energy market perspective. He testified that he was involved in dispatching the Vermillion units, along with the rest of the units in the joint dispatch, when the Vermillion Plant was a part of the Cinergy joint dispatch fleet. He stated that as a result of Cinergy separating the dispatch of its regulated and unregulated units in 2006, the Vermillion Plant has been dispatched as a part of the unregulated fleet. He noted that the Vermillion units are almost identical with the Company's Madison generating units and respond in a very similar manner. He stated that the Vermillion Plant will be a designated network resource with the units offered to the Midwest ISO day ahead and real time markets in essentially the same way Duke Indiana offers the Madison units.

Mr. Swez testified that the Vermillion Facility has access to two interstate gas transportation pipelines, Midwestern Pipeline Company through a Texas Eastern Transmission lateral, and, as a backup, Panhandle Eastern Pipeline Company through an Indiana Gas Company (Vectren) lateral, for delivery and parking services for the facility. He indicated that he expects the Company will utilize ProLiance Energy, LLC for gas purchases for Vermillion, as it does for a number of other gas-fired units.

Mr. Edward F. Kirschner, Director, Transmission Planning, Duke Energy Business Services LLC, provided information related to the electric transmission system of Duke Indiana, including the transmission system under the operational control of the Duke Energy Companies and jointly owned by Duke Indiana, Wabash Valley and Indiana Municipal Power Agency. He also provided background information regarding the Midwest ISO transmission requirements associated with new generation. Mr. Kirschner testified that since the Vermillion plant already exists and is connected to the transmission system, there is no Midwest ISO requirement for a generator interconnection study. He explained that Duke Indiana and Wabash Valley plan to classify the Vermillion Plant as a Designated Network Resource ("DNR"), which is a generating resource that can be nominated by a network customer under Module E of the Midwest ISO tariff as a qualified resource to meet their load requirements. Mr. Kirschner testified that Midwest ISO performed a generation deliverability study for the Vermillion Plant which showed the entire submitted nameplate capacity to be fully deliverable. As a result, he testified that Duke Indiana intends to nominate its portion of the Vermillion Plant to Midwest ISO as a DNR.

Mr. Kirschner testified that Duke Indiana requested that Midwest ISO perform a generation retirement study under Attachment Y of the Midwest ISO OATT in order to mitigate any potential transmission constraints in connection with the potential retirement of Gallagher Units 1 and 3. He stated that the 2009 study concluded that the retirement of Gallagher Units 1 and 3 would result in constraints on the Speed 345/138 kV transformer, and that Midwest ISO recommended a Speed 345/138 replacement project or other enhancements to relieve the loading on the Speed transformer. Mr. Kirschner testified that since the study was performed in 2009, Duke Energy submitted a request to Midwest ISO to determine if the results are still valid.

Mr. Kirschner explained that if the Gallagher Units 1 and 3 are retired in 2012, the Speed transformer would need to be placed in service by June 1, 2018 – an advancement of four years. He stated that the cost to Duke Indiana associated with this advancement would be approximately $0.4 million, using a present worth revenue requirement calculation.

Mr. Kent Freeman testified that Duke Indiana requests deferral for subsequent recovery of the retail jurisdictional portion of post-in-service carrying costs, depreciation expense, and transaction-related costs associated with the purchase of a portion of Vermillion, using a regulatory asset account (FERC CFR Account 182) until such costs are fully reflected in Duke Indiana's retail base rates after a general retail rate case. In addition, the Company requests that such carrying costs be accrued using Duke Indiana's AFUDC rates. He explained that without the relief requested, the incurrence by the Company of such costs would result in an adverse impact on the Company's earnings. He stated that the retail jurisdictional portion of the annualized Vermillion costs are estimated to be approximately $6.7 million. If the Company's deferred accounting requests are rejected by the Commission, the Company would experience annual earnings erosion, after tax, of approximately $5.2 million, until the conclusion of the Company's next retail electric rate case.

Mr. Freeman testified that the Company requests the following related to the proposed purchase of a portion of the Vermillion Plant: (i) that post-in-service carrying costs be accrued on the cost of the purchase of Vermillion and on the deferred depreciation and transaction-related costs, from the closing date of the purchase including accrual on previously computed post-in-service carrying cost amounts, until such costs are included in the Company's retail base rates; (ii) post-in service depreciation expense be deferred with respect to Vermillion from the closing date of the purchase, until the Vermillion plant is included in the Company's retail base rates; (iii) transaction-related costs for outside legal, engineering and consulting services provided up until the closing of the purchase be deferred for subsequent recovery over a five-year period beginning with the Company's next retail rate case. He opined that such accounting treatment is reasonable and appropriate from both a ratemaking and an accounting perspective. He further testified that such treatment will minimize the timing difference between cost recognition on the Company's books and cost recovery, will mitigate the adverse earnings impact, and will recognize the fact that the plant will be in service for the benefit of retail customers once the purchase is complete. Mr. Freeman testified that the accounting treatment proposed by the Company is in accordance with GAAP.

Mr. Freeman testified that the Company requests approval for the use of a regulatory asset account (FERC CFR 182) for the retail jurisdictional portion of the net book value for Gallagher Units 1 and 3, at the point they are retired, to allow for recovery of such remaining net plant balances through rates. He stated that, based on the Company's latest depreciation study filed in Cause No. 43114 IGCC 4S1, the expected average retirement dates for the two units, including the environmental equipment, is around 2026. He explained that for the Company to prevent the earnings erosion that would occur if the Company must expense the remaining plant balance and to enable the Company to fully recover the remaining costs associated with this investment made for the benefit of customers, a regulatory asset must be recorded for the remaining net book value. He testified that based on the current plant balance and estimated depreciation expense for the remainder of 2011, the Company estimates the net book value for Gallagher Units 1 and 3 to be approximately $79.7 million, $73.1 million on a retail basis, as of December 31, 2011. In addition, he stated the estimated dismantling costs are approximately $15.9 million, $14.6 million on a retail basis, based on the Company's latest depreciation study. He explained that the Company proposes that dismantling costs be treated as normal removal accounting and not included in the regulatory asset, which would result in a minimal rate impact in that the remaining net book value will be recovered over a similar timeframe as it would be if the units were not being retired, approximately 14 years. Mr. Freeman testified that a portion of the Gallagher Units 1 and 3 plant balance is environmental plant which is currently recovered under Rider No. 62 and Rider No. 71. He stated that the Company proposes to reduce both the original cost and accumulated depreciation associated with Gallagher Units 1 and 3 environmental plant from the Rider 62 balance. He also noted that upon retirement, the Company would stop depreciating the Gallagher Units 1 and 3 environmental plant resulting in lower depreciation expense recovered under Rider 61. Mr. Freeman testified that the accounting treatment proposed by the Company for the retirement of Gallagher Units 1 and 3 is in accordance with GAAP. Mr. Freeman opined that that the methodology resulting in the recovery of the net book value is reasonable and appropriate from both a ratemaking and an accounting perspective. He stated that allowing recovery of remaining net book balances is typical ratemaking treatment in circumstances such as these, where the property at issue has been in service and used and useful for over 50 years. He testified that if the requested accounting and ratemaking treatment is not granted, the Company would experience a significant adverse impact on earnings once the Gallagher 1 and 3 Units are retired.

Mr. Freeman testified that the Company requests authority to defer and subsequently recover the retail portion of costs incurred (and to be incurred) with respect to the Gallagher Units 1 and 3 gas conversion project including carrying costs using a regulatory asset account (FERC CFR account 182) until such costs are fully reflected in the Company's retail base rates after a general retail rate case. Duke Indiana requests that such carrying costs be accrued using the Company's AFUDC rates. He explained that although the gas conversion project was the best option for customers at the time the Company filed its case-in-chief testimony, the purchase of a portion of Vermillion became an even better option for customers and the Company should not be financially penalized for its pursuit of the initial Gallagher gas conversion option. For this reason, the Company requests authority to defer and subsequently recover the costs incurred (and to be incurred) in connection with maintaining the Gallagher gas conversion project as an option through the end of 2011. In addition, Mr. Freeman testified that should the Company's Attachment Y filing to the Midwest ISO, as discussed by Mr. Kirschner, requires any significant unexpected transmission plant upgrades in the near term, the Company requests authority to file supplemental testimony or a separate filing, depending on the timing of the Midwest ISO's response, requesting recovery of such costs. Mr. Freeman stated that as of April 20, 2011, the Company had spent a total of approximately $4.5 million on the Gallagher gas conversion project and estimates it will spend another $1.6 million through the end of the year, for a total of approximately $6.14 million by the end of 2011. The Company requested to defer for subsequent recovery the retail jurisdictional amount of the actual amount expended on the Gallagher gas conversion project through January 1, 2012, in an amount not to exceed $6.2 million, plus accrued AFUDC. Mr. Freeman testified that the regulatory asset would be amortized over five years starting at the time of the effective date of new retail base rates. Mr.

Freeman testified that the proposed accounting treatment for the gas conversion costs is in accordance with GAAP.

Mr. Freeman testified that although there are several variables that could affect the rate impact of the Vermillion purchase, the peak year average retail rate impact is estimated to be 0.6% when compared to total retail revenues for the twelve months ended December 31, 2010, as shown in Mr. Freeman's Exhibit T-2. Mr. Freeman also testified as to the reasonableness of the requested accounting and ratemaking treatment for the purchase of Vermillion.

6. **Wabash Valley's Direct Testimony.** Mr. Rick D. Coons, President and CEO of Wabash Valley testified in support Wabash Valley's request for a Certificate of Public Convenience and Necessity to purchase an additional 12.5% undivided ownership in the Vermillion Generating Station from Duke Vermillion and to request approval to issue long-term debt up to $13.6 million. He testified that the Vermillion Generating Station is located in Vermillion County in western Indiana. It consists of eight General Electric 7EA combustion turbines, each nominally rated at 80 MW, for a total of 640 MW. Wabash Valley currently owns a 25% undivided ownership in the Generating Station. The turbines are fueled by natural gas. The Vermillion Generating Station went into service in May, 2000. The units have an excellent operating history. The Generating Station is connected to the 345 kV line which is part of the joint transmission system owned by Duke Energy, IMPA, and Wabash Valley. Wabash Valley's proposal is to acquire another 12.5% undivided ownership in the Generating Station, the equivalent of an additional 80 MW.

Mr. Coons testified that the acquisition of new capacity at the Vermillion Station is consistent with Wabash Valley's long range power supply plans for three reasons. First, Wabash Valley is projecting a peak load of 1968 Mw in 2011. Wabash Valley serves that peak load requirement primarily through purchase power agreements and through owned generation. Wabash Valley has utilized a portfolio approach to its power supply planning. Wabash Valley's goal is to serve its member load through a diversity of resources and power supply entities. Mr. Coons believes the addition of owned generation to diversify Wabash Valley's portfolio is a reasonable approach to provide a hedge against a volatile wholesale market. He testified that the addition will certainly not result in Wabash Valley owning an over-abundance of self-generation and Wabash Valley will still have less than 60% of its power supply needs met by generation owned by the cooperative. Second, the acquisition of an additional undivided 12.5% ownership interest in a site comprised of eight units will provide Wabash Valley economies of scale as it relates to its ongoing O&M costs. Third, the current environment is a healthy environment in which to acquire generation assets on favorable terms. The current circumstances provide an environment where merchant plant developers want to decrease their asset holdings, and low interest rates are available to allow load-serving entities to acquire these assets on favorable terms. Acquiring generation facilities at this time will allow Wabash Valley to increase its long-term holdings without a significant upward rate adjustment.

Mr. Coons testified as to the benefits of the acquisition, the primary benefit of which is that it is at a price substantially below the original "cost to build." Wabash Valley is not aware of a better acquisition. The Vermillion Generating Station has been operable since the year 2000. It has a positive operating history, and the units are still relatively new. There is no construction or price risk associated with this acquisition. Further, the infrastructure of natural gas, electric transmission, operating personnel, air permits, etc. is already in place. The General Electric 7EA machines are dependable units that have been installed throughout the United States. Their relatively small size (summer rating of 71 MW) is a size that reduces the "outage risk" in Wabash Valley's power portfolio. Operating under a joint operating agreement with the other joint owner will spread the operating risk proportionately over eight units. Wabash Valley will share proportionately in the outage risk spread over the eight units at the Vermillion Generating Station.

Mr. Coons testified that, subject to the IURC and other governmental approvals, Duke Indiana will be purchasing the remaining 62.5% undivided interest from Duke Vermillion and that the total acquisition price for Wabash Valley is $13.6 million, or $170/kW. He testified that the Wabash Valley Board of Directors approved the acquisition and financing by board resolution on April 6, 2011. A Purchase Agreement has been executed by the parties and was attached and identified as Exhibit RDC-2 to his testimony.

Mr. M. Keith Thompson, Wabash Valley's Vice President of Power Production, testified to describe the physical assets of Vermillion Station currently jointly owned by Duke Vermillion and Wabash Valley. He testified that Vermillion Station is a nominal 640 MW peaking facility, comprised of eight (80 MW each) simple cycle, natural gas-fired, General Electric (GE) Frame 7EA combustion turbine generators, each with individual 94 foot exhaust stacks with silencers, separate cooling towers and each unit containing inlet air fogging. The units are equipped with dry low NO_x combustors and a Continuous Emissions Monitoring System to monitor the NO_x and CO_2 emissions. The Plant is located on a 136 acre tract of rural farmland across State Road 63 from Duke Indiana's Cayuga generating station.

Mr. Thompson testified that Wabash Valley originally acquired a 25% undivided ownership interest in Vermillion Station for $52.4 million or $328/kW in 2004. The value of capacity in the Midwest ISO footprint has decreased on a $/kW basis since Wabash Valley's original Vermillion acquisition. He testified that he believes the capacity market will begin to recover in calendar year 2012 as the economy recovers and as pending environmental regulations are imposed on coal-fired electric generating units.

Mr. Thompson testified that the Plant has two separate physical natural gas lines the can supply gas to Vermillion: Midwestern Gas Pipeline interstate mainline - via a 16 inch, 14.5 mile Texas Eastern Lateral (this is the main natural gas line serving the plant), or Panhandle Eastern Pipeline interstate mainline - via a 16 inch, 10 mile Indiana Gas Lateral (This connection is capable of supplying the natural gas requirements of four of the eight GE 7EA combustion turbines.). He further testified that the Plant is connected to the adjacent Duke Indiana Cayuga substation at 345kV, via a short, two span connection. He testified that presently the Plant is operated and maintained by Duke Vermillion, via an affiliate service company, under a 3 year term Operation and Maintenance Agreement dated August 1, 2010.

Mr. Thompson testified that Wabash Valley has owned an undivided ownership interest in Vermillion since 2004 and is comfortable with the equipment, operations, maintenance, and inventory levels at Vermillion. Wabash Valley personnel participate in monthly operations conference calls and visit Vermillion on a regular basis

Mr. Lee R. Wilmes, Wabash Valley's Vice President, Power Supply, testified to: (a) describe Wabash Valley's need for additional generation; (b) review Wabash Valley's plans for meeting those needs with the purchase of an additional 12.5% share of the Vermillion Generating Station; (c) review the alternative power resource options that Wabash Valley has available to meet those needs; and (d) review how the purchase of this capacity is consistent with Wabash Valley's Integrated Resource Plan ("IRP") and State Utility Forecast Group's ("SUFG") "Indiana Electricity Projections: The 2009 Forecast." He testified that the need for new generation resources is a function of Wabash Valley's supply obligations and existing generation resources, both owned and under contract.

Mr. Wilmes testified that Wabash Valley has an obligation to supply all-requirements power to 28 electric cooperatives (member systems); 22 are located in Indiana; 3 are located in Illinois; one is located in Ohio; one is located in Michigan; and one is located in Missouri. He testified that on January 13, 1978, this Commission, in Cause No. 35091, granted to Wabash Valley a Certificate of Public Convenience and Necessity to operate as a public utility, including the authority to, among other things, serve as a power supplier to its members and to construct, own, and operate generation, transmission, and related plants and facilities. He testified that Wabash Valley has also entered into individual contracts with each of 25 members to serve their full electric power and energy requirements through the year 2050. During 2004 and 2005, three Members gave notice of their intent to buy out and exit from Wabash Valley at the end of 10 years (the "Buy-out Period") with an option to rescind their decision during the first 7 years of the Buy-out Period. Two of the three Members must exercise this option to rescind by the end of 2011. The third has until the middle of 2012. At that time, these Members will be committed to stay with Wabash Valley or exit from the association. For long-range planning purposes, Wabash Valley is forecasting that two of the Members will no longer be supplied by portfolio resources after 2014, and one of the Members will no longer be supplied by portfolio resources by mid-2015.

Mr. Wilmes testified that in the 2009 IRP, Wabash Valley projects that the electric needs for its members will grow at an average of 0.8% per year over the next twenty years. The expected load growth increases Wabash Valley's power requirement by approximately 30-35 MW per year. Wabash Valley also supplies power to several large industrial loads; however, the costs and power relating to these loads are directly passed through to the customer under Wabash Valley's Industrial 2 tariff. The large industrial loads are included in the Wabash Valley total planning load because Wabash Valley has the ultimate responsibility to meet these consumers' energy requirements and to meet the minimum reliability requirements.

Mr. Wilmes testified that Wabash Valley will meet these through a combination of: (a) existing generation and power contracts; (b) load management and distributed generation; (c) energy efficiency programs; and (d) new supply resources. These new resources may be long-term purchased power contracts, generating facilities owned by Wabash Valley, and short-term wholesale market purchases. He testified that the plan includes Planned Additions beginning in 2010 of additional landfill gas plants, additional demand response, and additional distributed generation. After those IRP Planned Additions, Wabash Valley will need additional generation in 2013 and 2014. Depending on the decision of the three Members with the option to leave the Association in 2014-2015, Wabash Valley will either continue to need additional generation in 2015, or will have sufficient supply through 2017. Starting in 2018, regardless of the three members' decision, Wabash Valley will have a need of nearly 300 MW.

Mr. Wilmes testified that the purchase of an additional 12.5% of Vermillion would bring an additional 80 MW of peaking generation to the portfolio. However, Wabash Valley currently has two purchased power agreements with Duke Energy Ohio for 50 MW through 2013 and 50 MW through 2014 supplied by Duke Vermillion's share of the Plant. Because Duke Vermillion, a subsidiary of Duke Energy Ohio, is selling its entire share of Vermillion, those purchased power contracts will terminate. The net result is a 20 MW reduction of capacity in 2012 and 2013, 30 MW additional capacity in 2014, and an 80 MW addition in capacity starting 2015.

Mr. Wilmes testified that after the acquisition of the additional 12.5% of Vermillion, the percent of Wabash Valley peak requirement supplied by peaking generation will be less than 20%. That is within the planning criteria stated in the 2009 IRP of having no more than 35% of peak requirements supplied by peaking resources. Based on Wabash Valley's annual load shape, Wabash Valley needs approximately 60 to 65% of its peak in base resources. Any needs above this level would be more economical to supply with peaking resources.

Mr. Wilmes testified that Wabash Valley considered a variety of alternatives when it evaluated the Vermillion Generating Station units. These included: (a) estimated cost of construction of new generation alternatives; (b) periodic formal and informal requests for proposals for power purchases; and (c) opinion of experts of the value of the Vermillion Generating Station units compared to expected wholesale market prices and other peaking resource alternatives. Wabash Valley is purchasing the 12.5% undivided share of Vermillion for $13.6 M or 80 MW at $170/kw. The Wabash Valley 2009 IRP assumed an installed cost for new peaking generation of $650/kw or $38.4 M more than the Vermillion purchase. In addition, these units are already built and operating, and as such, they have no construction cost risk.

Mr. Wilmes testified that the Vermillion Generating Station purchase is consistent with Wabash Valley's need for additional power supply resources as expressed in Wabash Valley's IRP. Additionally, this project is consistent with Wabash Valley's plan to look for opportunities for alliances and partnerships, including participation in power production facilities, as expressed in the two-year work plan. The cost of the Vermillion Generating Station purchase is substantially less expensive than the cost of expansion peaking units evaluated in the IRP, without the risks associated with new unit construction.

Mr. Wilmes testified that Wabash Valley has a number of arrangements with other electric utilities or entities to reliably meet the member system loads. Wabash Valley is a joint owner of ACES Power Marketing ("APM") with other generation and transmission electric cooperatives. APM provides risk management services and support to manage fuel and power purchases in the short-term market (through 12 months). Wabash Valley is a joint owner in Gibson Unit 5 and works with Duke Indiana and the Indiana Municipal Power Agency to jointly operate the unit. Additionally, Wabash Valley jointly owns transmission with Duke Indiana and

Indiana Municipal Power Agency in order to deliver power to its load in the Duke-IN balancing area. Wabash Valley also jointly owns with Hoosier Energy Rural Electric Cooperative, Inc. the Lawrence County peaking generation facility and the Holland combined cycle facility in Illinois. Wabash Valley also has mid and long term base load power purchase agreements with American Electric Power, Duke Indiana, and Hoosier Energy, along with purchases from wind generation facilities owned by NextEra and Exelon.

Mr. Wilmes testified that the 2009 SUFG forecast indicates that the State will need 480 MW of peaking capacity and a total of 1,320 MW of generation capacity by 2015. Wabash Valley understands that Duke Vermillion's portion of Vermillion is not included in the SUFG's capacity forecast since it is not currently owned by a regulated Indiana utility.

Ms. Nisha A. Harke, Wabash Valley's Manager of Finance & Rates testified to present financial support for Wabash Valley to be authorized to execute promissory notes as evidence of indebtedness for financing up to $13,600,000 for the purchase of an additional 12.5% interest in the Vermillion Generating Station. Wabash Valley is seeking financing approval for the acquisition of an additional 12.5% interest in the Vermillion Generating Station, the equivalent of an additional 80 MW. Wabash Valley currently owns a 25% undivided ownership interest in the Vermillion Generating Station. Wabash Valley seeks approval for and proposes to finance up to 100% of the purchase price of $13.6 million through competitive lenders such as CoBank or Private Placement lenders. Wabash Valley intends to sign one or more promissory notes to finance this acquisition for up to 20 years at an estimated interest rate of 5.7%.

Ms. Harke testified that under the estimated calculations of interest expense and principal payments, the annual debt service payment for the note related to this capital acquisition would be approximately $1,157,000 based on an interest rate for 20 years of approximately 5.7% and an aggregate loan amount of $13,600,000. The loans will be secured by property owned by Wabash Valley, under Wabash Valley's Mortgage and Indenture of Trust. She testified that Wabash Valley's current rates will generate adequate revenues to repay the debt service obligations. Wabash Valley's Indenture of Trust requires a TIER of 1.0 or better and a Debt Service Coverage Ratio of 1.15 or better. She testified that while the minimum financial covenants of the Indenture could still be met, the Wabash Valley Board of Directors has the authority to increase rates during the course of the year. Wabash Valley became FERC regulated on July 1, 2004, and under that structure, Wabash Valley can recover all costs needed to meet the Board-approved budget and margin. If costs are in excess of the amount collected, those costs are 'trued up' at the end of the year and collected over the next 12 month period. Wabash Valley also has the ability, through its FERC formulary rate, to recover fuel costs and the energy cost component of power purchases prior to the 12 month recovery period if the Board should choose to accelerate recovery of these costs. Ms. Harke testified that any acquisitions financed using long-term debt by Wabash Valley need to meet the requirements of the Trust Indenture, and any notes issued will require the authorization from the Trustee under the Indenture of Trust and approval by the lender.

7. **Duke Vermillion's Direct Testimony.** Duke Vermillion presented the testimony of Mr. Gregory H. Cecil, Vice President, General Dispatch and Logistics, Duke Energy Commercial Enterprises. He testified as to the background and explanation of the proposed asset

sale of Duke Vermillion's ownership interest in the 640 megawatt natural-gas fired merchant plant in Vermillion County, Indiana ("Vermillion Facility") to Wabash Valley and Duke Indiana. He described the negotiations that led to the proposed asset transfer and he also supported confirmation of the Commission's declination of jurisdiction over Duke Vermillion's ownership and the sale of the Vermillion Facility, or to the extent necessary, approval of Duke Vermillion's proposed asset sale by the Commission. He also explained why after the sale of the Vermillion Facility, Duke Vermillion should no longer be considered a public utility by the Commission.

Mr. Cecil described the Vermillion Facility and its regulatory background. He testified in 1999 a Cinergy merchant affiliate and a Duke Energy affiliate jointly developed and owned a number of gas-fired plants in the Midwest, including the Vermillion Facility. As part of the dissolution of that joint venture ownership in the Vermillion Facility was transferred to Duke Energy Vermillion, LLC. Vermillion LLC was established as and granted FERC authority as an Exempt Wholesale Generator ("EWG") under the Public Utility Holding Company Act of 1935. The Vermillion Facility is interconnected with the transmission system of Duke Indiana and the output of the Vermillion Facility is exclusively sold into the wholesale market.

Mr. Cecil testified that on April 30, 2004, Vermillion LLC sold Wabash Valley an undivided 25 percent ownership interest in the Vermillion Facility and Wabash Valley was issued a Certificate of Public Convenience and Necessity by this Commission on March 17, 2004 in Cause No. 42495. In connection with the sale to Wabash Valley, Vermillion LLC obtained a redetermination from FERC of EWG status on February 17, 2004. Thereafter, on February 8, 2006, in Cause No. 42929, the Commission approved Vermillion LLC's transfer by merger of its 75 percent ownership interest in the Vermillion Facility to its affiliate Duke Energy Ohio, and declined jurisdiction over the acquisition, ownership, and operation of, and financing, accounting and ratemaking for the Vermillion Facility. Most recently, on December 29, 2010, in Cause No. 43965, the Commission continued to decline its full jurisdiction over the ownership of the Vermillion Facility, resulting in the transfer of the Vermillion Facility assets from Duke Energy Ohio to Duke Vermillion.

Mr. Cecil went on to explain that in 2011, Duke Energy Ohio restructured its generation business pursuant to FERC authorization and some of its gas-fired generation assets were transferred to separate, affiliated LLC companies, including the Vermillion Facility's transfer to Duke Vermillion. Currently, Duke Vermillion owns an undivided 75 percent of each generating unit and Wabash Valley owns 25 percent of each generating unit.

Mr. Cecil explained the sale and negotiation process between Duke Vermillion and Wabash Valley. He explained that over the past several years, the owners of the Vermillion Facility had explored avenues to reduce their number of gas fired merchant plants and reallocate capital resources to investments in renewable generation. In 2010, Pace Global was hired to help identify potential buyers for certain merchant plants. Approximately 30 parties were contacted by Pace with a number of them expressing interest in further discussions. Simultaneously, Duke Energy Ohio also identified an additional 10 to 15 entities with which it already had established relationships including Wabash Valley and Hoosier Energy.

Mr. Cecil testified that he met with Wabash Valley in September, 2010, to discuss their interest in acquiring all or a portion of Duke Energy Ohio's 75 percent interest in the Vermillion Facility. Wabash Valley expressed interest and also indicated they would need a partner to acquire the entire 75% interest. Thereafter, in October, Mr. Cecil met with Hoosier Energy to discuss their interest in merchant plant acquisition. Later that year, both Wabash Valley and Hoosier made further inquiry regarding Vermillion and another gas merchant plant. Mr. Cecil testified that given that both Wabash Valley and Hoosier Energy are generation and transmission providers for rural electric membership cooperatives they seemed to him to be logical partners for the acquisition of Vermillion or another gas merchant plant. In December 2010, Mr. Cecil contacted Wabash Valley to determine their interest in changing their undivided ownership interest in the Vermillion Facility into ownership of specific turbine generators. At that time, Wabash Valley indicated that they did not have an interest in the ownership of specific Vermillion units, but may have an interest in purchasing the entire Vermillion Facility and would explore potential acquisition partners.

On February 8, 2011, Wabash Valley offered to purchase Vermillion with the proviso that two tolling agreements be cancelled. Thereafter, Duke Energy Ohio provided a counteroffer to Wabash Valley which was verbally accepted on February 28, 2011. On March 3, 2011, Mr. Cecil sent Wabash Valley a draft letter of intent. Wabash Valley's March 9, 2011 response referenced its discussions with a "third party" and the third party's joint purchase of the Vermillion Facility. Wabash Valley did not identify the third party. On March 14, 2011, Wabash Valley and Duke Energy Ohio signed the letter of intent. Mr. Cecil testified it was not until April 25, 2011, that Wabash Valley informed him that Duke Indiana was the third party working with Wabash Valley in the Vermillion Facility purchase.

Mr. Cecil testified that the negotiations with Wabash Valley were good faith, arms-length negotiations with Wabash Valley and Duke Vermillion both working for the best deal possible. He testified that had he known Wabash Valley had partnered with Duke Indiana, the negotiation terms and demands would have been no different. Duke Vermillion had set certain price and terms objectives that had to be met before a sale with any entity could move forward. Those objectives were satisfied with the Wabash Valley negotiations and would not have been diminished if it had been known Wabash Valley was negotiating for results acceptable to itself and to Duke Indiana.

Mr. Cecil sponsored the executed Facility's Interest Purchase Agreement. As a result of that agreement, upon regulatory approvals, the final undivided ownership interest shares of the Vermillion Facility will be 62.5 percent for Duke Indiana and 37.5 percent for Wabash Valley. Closing on the transfer is contingent upon approval by this Commission and approval by the FERC.

Mr. Cecil testified that both Wabash Valley and Duke Indiana have long track records of owning and operating large, electric generation assets in Indiana and based on his experience, they both have the financial, technical, and managerial ability to own and operate the Vermillion Facility. He explained that after the transfer, the Facility will continue to be managed, operated, and maintained by qualified Duke Energy personnel and will continue to have the financial backing and strength of Duke Energy and Wabash Valley.

Mr. Cecil testified that continued declination of jurisdiction over the ownership and transfer of the Vermillion Facility is consistent with the public interest and the requirements of Ind. Code ch. 8-1-2.5. He explained competitive forces in the wholesale power market and FERC's regulation of Duke Vermillion render the exercise of jurisdiction by this Commission unnecessary, burdensome, and wasteful of the Commission's time and resources. He pointed the Commission found these criteria satisfied when it previously declined to exercise jurisdiction over the Vermillion Facility's ownership and operation in Cause No. 41388 and 42929. Following this asset transfer, Duke Vermillion will not own, operate, manage, or control any generation assets, or any other plant or equipment within Indiana for the production, transmission, delivery, or furnishing of heat, light, or power. He stated approval of the transfer will be sought and obtained from FERC.

Mr. Cecil also noted that Wabash Valley and Duke Indiana have sought issuance of Certificates of Public Convenience and Necessity from this Commission for their ownership interest the Vermillion Facility and thus there is no need now, for the first time, to assert jurisdiction over Vermillion's ownership of these assets just at the time that the FERC will review for approval the proposed asset transfer and the two public utility purchasers will have the Commission review each of their asset acquisitions under a Certificate of Need proceeding.

Mr. Cecil pointed out this Commission's prior declination of jurisdiction over Vermillion's ownership of the Facility. In Cause No. 41388, April 7, 1999, the Commission declined to exercise jurisdiction over the construction and operation of the Vermillion Facility. Thereafter, in Cause No. 42929, February 8, 2006, the Commission approved the transfer to Duke Energy Ohio, by merger, of Vermillion LLC's 75 percent interest in the Vermillion Facility, with 25 percent owned by Wabash Valley. Therein, the Commission declined to exercise jurisdiction over Duke Energy Ohio's acquisition, ownership, operations, financing, accounting, in ratemaking for the Vermillion Facility. Similarly, in Cause No. 43965, December 29, 2010, regarding transfer of the Vermillion Facility from Duke Energy Ohio to Duke Vermillion, the Commission declined jurisdiction over Duke Vermillion and the Vermillion Facility, including declination of jurisdiction over "...ownership, operations, accounting, financing, and rates of the Vermillion Facility." Thus, Mr. Cecil concluded the Commission has previously found it reasonable to decline jurisdiction over Duke Vermillion's ownership of the merchant Vermillion Facility and he testified the Commission should continue to decline jurisdiction over the ownership and transfer of that Facility as that jurisdiction relates to Duke Vermillion.

Finally, Mr. Cecil testified that after transfer of the Vermillion Facility, Duke Vermillion will no longer own any electric generating assets in Indiana and will have no public utility attributes. It will not provide retail or wholesale electric utility service. As such, he testified Duke Vermillion should no longer be considered a public utility by the Commission and asked the Commission to confirm that any public utility requirements, including reporting requirements contained in prior IURC orders such as annual reports, should be removed from Duke Vermillion.

8. **OUCC's Evidence.** Mr. Anthony Alvarez, a Utility Analyst II for the OUCC, testified that Duke Indiana is anticipating the retirement of some of its generation units in the very near future and it will need additional capacity to cover for the retired units and to meet the required reserve margin. He stated that the 400 MW share of the Vermillion Plant's capacity is sufficient to cover for the retirement of Gallagher Units 1 & 3. Once the 630 MW Edwardsport IGCC goes on line in 2013, Duke Indiana's reserve margins will increase from 20.9% to 26.3%, and Duke Indiana's excess capacity will rise from 520 MW to 763 MW. He explained that by smoothing out the load growth, the relationship between peak load projection and capacity addition/retirement trend is eliminated and Duke Indiana will have enough capacity to cushion the retirement of the Wabash River Unit 2, 3 and 5 (-661 MW). He determined that the acquisition price of $170/kW seems reasonable and cost effective by assuring reliability of having enough capacity in the system to cover retirement of various units the Petitioner is anticipating in the near future.

Mr. Alvarez noted that FERC has already approved the sale of the Vermillion Plant, thus, eliminating the necessity of the proposed Gallagher Gas Conversion Project to maintain existing capacity, or as an alternate Plan B. He also noted that Duke Indiana President Mr. Esamann together with other Duke Indiana Witnesses, Ms. Jenner and Ms. Hager, were unanimous in their decision that the Vermillion Plant purchase is a better option against the Gallagher Gas Conversion. He added that pursuing the Gas Conversion Project will only hinder and delay the adoption of new, efficient, and effective gas turbine technology, leaving Indiana with old, vintage 1950's gas-fired boiler technology.

Mr. Alvarez testified that, based on his analysis of Petitioner's Exhibit O-4, Duke Indiana projects a high capacity growth rate of 3.01%, and a peak load growth rate of 1.73% in the short-term (2011-2014). He stated that the short-term high capacity growth rate is accounted for by the Vermillion Plant (353 MW) and the IGCC (586 MW), however he noted that Duke Indiana's short-term growth rate seems overstated. He discussed his analysis and calculated Duke Indiana's peak load growth rate for the period 2008 to 2015 using historical data from Duke Indiana's summer reliability presentation to the Commission (2005-2011) and Duke Indiana's forecast in Petitioner's Exhibit O-4 (2011-2015). He stated that Duke Indiana projects a high peak load growth rate from 2011 to 2014 that counter balances the additions of the Vermillion Plant and the IGCC (Planning Reserve Margin of up to 22.1%). He went on to state that in 2015, Duke Indiana projects the retirement of Wabash River Units 2, 3, and 5 (together totaling 661 MW) and at the same time projects a negative peak load growth at 3.34%, effectively dropping its peak load forecast close to the 2012 level. As a result, Mr. Alvarez stated that Duke Indiana's short-term peak load projections seem to be in harmony with planned and expected capacity additions and retirements. Mr. Alvarez went on to state that using the same data compilation in calculating Duke Indiana's peak load growth, he calculated the Company's historical, long-term and short-term peak load growth three-year moving average and compared it with EIA's data focused on the same 2008 to 2015 time period. Mr. Alvarez testified that wide swings in Duke Indiana's short-term peak load projections run counter to EIA's latest forecast, which took into account the recent and persistent economic downturn. He stated that Duke Indiana's short-term peak load projections mimic the trend of its own capacity addition and retirement.

Mr. Alvarez testified that Duke Indiana's 1.5% growth forecast seems overstated, and that it is more reliable to use Duke Indiana's long-term compound average growth rate of 0.71% as the escalation factor to smooth out the wide swings of its short-term peak load projections. He stated that smoothing out the wide swings is critical in negating the direct relationship that previously existed between the peak load projection and capacity addition/retirement trend. Mr. Alvarez testified that once the IGCC goes on line in 2013, Duke Indiana will realize increases in the reserve margin (from 20.9% to 26.3%) and excess capacity (rising from 520 MW to 763 MW). Mr. Alvarez testified that by smoothing out the load growth, the seemingly direct relationship between the peak load projection and the capacity addition/retirement trend is eliminated and the resulting calculations show that Duke Indiana will have enough capacity to alleviate the pressure of retiring the Wabash River units.

Mr. Alvarez expressed concern regarding technical operating limitations, deficiencies and issues of the Vermillion Plant as a peaker plant. He testified that the GE Frame 7EA gas turbines are General Electric's mid-range power platform offering: well suited for peak, cyclic or base load operations with fast-start-fast-load capability, the Vermillion Plant does not have any of these capabilities. He also stated that the Vermillion Plant heat rate is more than the manufacturer's performance specification and burns more fuel to generate the same amount of electricity. He explained that although there are currently two gas supply laterals serving the Vermillion Plant, one of the laterals has a restricted flow rate. He stated that despite being a peaker plant, the Vermillion Plant is not fast-start-fast-load capable, nor is it black start capable. It is somewhat, disadvantaged with a low capacity factor and a high heat rate, placing it low in the dispatch stack.

Mr. Alvarez next discussed Duke Indiana's stated short- and long-term benefits of the gas conversion project. With regard to the claimed short-term benefit of being able to maintain capacity near load centers, Mr. Alvarez testified that although there are inherent benefits, the use of various regional transmission and operation systems allow diversity and enable integration of generation and load centers over a large organized market footprint. With respect to the gas conversion project improving the generating station's environmental footprint, Mr. Alvarez states that if the conversion to gas is implemented, the Consent Decree already requires the installation of a number of combustion control equipment to reduce emissions of nitrogen oxides ("NO_x"), such as low-NO_x natural gas burners, an overfire air system, and a Flue Gas Recirculation System ("FGR"). There may be more emission control equipment needed for the gas conversion to comply with the Consent Decree, in addition to potential capital projects needed for the vintage 1950's gas-fired converted boilers to sustain compliance with future environmental regulations.

As to long-term benefits, Mr. Alvarez testified that the conversion project will not play a substantial role in positioning Duke Indiana to respond to either a state or federal mandated RPS. Duke Indiana's proposal appears to contradict the EPA's RPS position of actually displacing some gas-fired generation. Mr. Alvarez dismisses Duke Indiana's stated benefit regarding the ability to co-fire biomass fuel at the site at a later date, noting that Duke Indiana did not provide information supporting the claim, and the technology, infrastructure and economics required are non-existent, or at best, wide ranging. As to Duke Indiana's stated long-term benefit of the gas pipeline providing flexibility for a new gas turbine or combined cycle units in the future, Mr.

Alvarez testified that constructing 19.5 miles of high pressure gas pipeline today just to have the flexibility for a new gas turbine or combined cycle units in the future is not economically sound.

In response to Duke Indiana's claim that the converted units will operate as peaking units with low capacity factors (less than 10%), Mr. Alvarez does not expect the converted gas-fired units to do any better than the large majority of Duke Indiana's peaker plants that operate at Capacity Factors of less than 2%. In addition, Mr. Alvarez testified that in comparison to a gas turbine, the cost of fuel used to startup alone is very high for gas-fired boilers.

Mr. Alvarez explained that Mr. Roebel's description of the converted gas-fired boilers as being "more cyclic operation," simply means that the units cannot run for a longer period of time (very low capacity factor). He also explained that Mr. Roebel's expectation of the converted units to have "longer periods of economic shutdown," simply means, that the converted unit's variable operating and maintenance ("O&M") costs make it un-economic and very expensive to run, but rarely and only to meet the highest peak (very low in the order of the dispatch stack).

Mr. Alvarez testified that in the Petitioner's last rate case in 2003 (Cause No. 42359), the net cost of dismantling the Gallagher units was calculated and included in the Depreciation Study. Witness John J. Spanos of Gannet Fleming, Inc., testifying for then PSI Energy, Inc. (Petitioner's predecessor), included a "negative net salvage value concept" in his depreciation study that seems to have rolled these costs into the existing rates.

In summary, Mr. Alvarez testified that the additional Vermillion Plant capacity more than covers for the retirement of the Gallagher Units 1 and 3 capacity. He stated that pursuing the Gas Conversion Project will only hinder and delay the adoption of new, efficient and effective gas turbine technology leaving Indiana with old, vintage 1950's gas-fired boiler technology. In addition, he noted that there is a very high risk of construction costs escalation pertaining to the conversion of the Gallagher units to gas and installing a natural gas pipeline. The OUCC recommended the issuance of a CPCN to Duke Indiana and Wabash Valley for the purchase of the Vermillion Plant and denial of the Gallagher Conversion Project.

Ms. Cynthia M. Armstrong, a Utility Analyst for the OUCC, explained that the OUCC opposes any recovery of costs associated with allowance surrenders resulting from the Consent Decree. She stated that the surrender of EAs is a remedial measure to rectify the harm caused by Duke Indiana's excess emissions resulting from its failure to secure a NSR or PSD pre-construction permit and to install the appropriate pollution control equipment that would have been required in order to obtain such a permit, and that such remedial measures that result from a utility's past wrongdoings should not be included in rates. Ms. Armstrong explained that, while it may have been prudent for Duke to enter into the Consent Decree to avoid a harsher court-ordered remedy, the primary reason Duke Indiana entered into the Consent Decree and is incurring the additional EA costs is because the company violated environmental law. She reasoned that ratepayers entrust Duke to manage its assets efficiently and within the confines of the law, and added that ratepayers have no control over how Duke chooses to run its operations. She testified that it is unfair for ratepayers to have to pay for the EA costs resulting from Duke Indiana's legal violations and flawed business decisions. In addition, Ms. Armstrong asserted that these allowance costs are not relevant to providing electric service since they must be surrendered and recorded as consumed without being available for the provision of additional electric generation. If the EAs are recovered through rates, customers will be charged more in consumption costs without receiving an additional benefit or service for the allowance surrender. Ms. Armstrong suggested that the OUCC's ability to participate in settlement negotiations that lead to Consent Decrees is limited, if not precluded entirely, by federal courts. She noted that if IOUs know that they are able to pass EA surrender costs and environmental mitigation project costs that result from a consent decree onto ratepayers, they may have more incentive to negotiate greater allowance surrenders and more expensive mitigation projects in exchange for lower civil penalties. Furthermore, they might have less incentive to keep all compliance costs resulting from such settlements as low as possible.

Ms. Armstrong responded to Mr. Roebel's assertion that, with respect to the surrender of allowances pursuant to the Consent Decree, the Commission may take into account the reasonableness of the Company's actions at the time they were taken considering what the Company knew or reasonably should have known at that time. She stated that Duke is minimizing the issue that it violated the law and that a federal jury found the company legally culpable when it asks the Commission to find its actions prudent. Ms. Armstrong testified that the OUCC finds it difficult for Duke Indiana to justify recovery of EA surrender costs without re-litigating the issues from the NSR Litigation.

Ms. Armstrong stated that, in essence, the Company asks the Commission to find that Duke Indiana should not have expected NSR to apply to the Gallagher Units 1 and 3 pulverizer replacement and, in effect, to hold the company harmless in its actions by undertaking these projects without first obtaining the necessary pre-construction permits to do so. She stated that this is an unreasonable request of the Commission since (1) the courts have already decided this issue, (2) the Commission has not had full access to all filings in this case, nor has it been present in all proceedings before the court on this issue; and (3) the Commission does not have the jurisdiction to decide whether the NSR provisions of the Clean Air Act applied to these projects.

She stated that Duke Indiana is essentially asking the Commission to make a finding that the EPA changed the way it interpreted and applied the NSR rules from the early 1980s until the late 1990s. She noted this is a legal issue that has yet to be determined by the courts. She stated that the Commission should not be required to make a finding that is contrary to a determination by the federal agency in charge of enforcing federal environmental law.

Ms. Armstrong testified that the OUCC does not consider the Company's decision to replace the Gallagher pulverizers without first obtaining an NSR or PSD permit as being reasonable. She noted that any company that has a question regarding the applicability of NSR to a particular project can ask the EPA to evaluate the project and make a determination whether or not NSR would apply. Such prudent action provides a sort of insurance policy to a company wishing to undertake a project at one of its existing facilities. She stated that if the EPA would have considered the pulverizer replacements to fall under the Routine Maintenance, Repair, or Replacement (RMRR) exception after Cinergy asked for an NSR applicability determination, Cinergy would have a signed document from the EPA declaring the project to be exempt from NSR and would have assurance that it could complete the replacement without needing a pre-construction permit to do so. Cinergy did not seek an NSR applicability determination from the

EPA for the Gallagher pulverizer replacements. Ms. Armstrong further noted these pulverizer replacements occurred during a time when Cinergy was aware (or should have been aware) that the EPA was growing concerned that several projects utilities had undertaken without NSR or PSD permits in the past were not exempt under the RMRR exclusion, and the agency was issuing information requests to investigate these projects in more detail. Ms. Armstrong noted that Duke had already presented these arguments before a jury, and the jury found that a reasonable plant owner undertaking the pulverizer modifications should have expected the projects to result in emissions increases. If, after hearing all of the evidence that Duke and the plaintiffs offered during the second liability trial, the jury found these projects to be major modifications that resulted in significant net emissions increases, Ms. Armstrong suggested that a reasonable person would have expected NSR to apply to the Gallagher pulverizer replacements.

Ms. Armstrong added that Duke Indiana provided a wealth of evidence in its Case-in-Chief regarding the laws, regulations, and decisions regarding RMRR, how it applies to NSR, and how it believes the EPA has changed its interpretation of RMRR over the years. Furthermore, she noted Duke Indiana also presented evidence explaining why it believed the Wabash River projects fell under the definition of RMRR. However, Ms. Armstrong noted, Duke did not present an RMRR defense for the Gallagher pulverizer replacements in court. Rather, she noted, Duke offered very little evidence in its Case-in-Chief in this Cause supporting Duke's position that the Gallagher project was not a major modification that resulted in regulated pollutant increases under the Clean Air Act. She noted Mr. Pearl stated he was on a project team that performed a comprehensive evaluation of the pulverizer replacements in 1997, and his role was to make sure the team was aware of the triggers for NSR. However, he does not discuss precisely how and why his team concluded that NSR would not apply to the pulverizer projects and that no permit was necessary prior to undertaking the projects.

In response to Duke Indiana's assertion that customers have benefited from the lower cost of electricity provided by these units without pollution control equipment, Ms. Armstrong stated that Duke's (Cinergy's) customers have no control over how the utility chooses to operate its units. These business decisions rest in the hands of Duke's executive and engineering staff. The company chose to make modifications to its generating facilities without going through the NSR construction permitting process or obtaining an applicability determination from the EPA on these projects. She added that it was the Company's choice to litigate these claims, and it was the Company's choice to enter into the Consent Decree. She noted ratepayers were given no opportunity to be heard in any of these matters.

Ms. Armstrong stated that the OUCC has generally been supportive of the pollution control projects Duke has proposed before the Commission. She added that the Commission has approved approximately $1.8 billion in pollution control equipment that is currently tracked through Duke's ECR proceedings. Ms. Armstrong stated that one of the reasons the OUCC supported these extensive environmental compliance projects was because the OUCC believed this would lead to settling NSR claims made against Cinergy with the EPA. She suggested the OUCC would possibly have supported any reasonable steps that Duke would have taken to comply with environmental laws with regards to the Gallagher Generating Station. But she disagreed with Duke's proposal to make ratepayers responsible for the EA surrender costs associated with the Consent Decree simply because they have unknowingly enjoyed lower rates due to Duke's violation of the law. Ms. Armstrong stated that Duke seeks acceptance of its unlawful actions through the defense that it cost less not to comply with the law.

Ms. Armstrong expressed her understanding of Duke's request in this cause that it did not seek recovery for environmental mitigation costs. Further, she noted, Duke Indiana indicated it does not intend to seek recovery of the $1.0 million in environmental mitigation projects the company must provide to New York, New Jersey, or Connecticut. However, she noted Duke Indiana does reserve the right to seek recovery of all or a portion of the five million dollars in remaining environmental mitigation expenses, depending on what project the Company ultimately implements. Ms. Armstrong also expressed the OUCC's reservation of the right to object to recovery of these costs if or when Duke requests rate relief for them.

Ms. Armstrong testified regarding the impact of new environmental regulations on the Vermillion acquisition and Gallagher Gas Conversion Project. She stated that the Mercury and Air Toxics Standards (MATS) will require stringent emissions standards for coal and oil-fired generating units which will be difficult for many coal-fired electric generating units to meet and will likely require additional expensive retrofits. She stated that one strategy to comply with MATS would be to replace coal-fired generation with natural gas generation or include more natural gas generation within the electric utility's portfolio. Ms. Armstrong estimated that as a result of the Cross State Air Pollution Rule (CSAPR), Duke Indiana will need to cut SO_2 emissions by more than 16,000 tons per year beginning in 2012 to be in compliance. She indicated that Duke Indiana should be able to meet these emissions cuts by operating the trona injection systems on Gallagher Units 2 and 4 and retiring Gallagher Units 1 and 3 or repowering in 2012. However, she stated that beginning in 2014, Duke Indiana will have to reduce SO_2 emissions by more than 52,000 tons per year to meet the 2014 CSAPR caps. She stated that the Company will need to focus on the Wabash River units for these additional reductions. Since Duke Indiana plans to retire Wabash River Units 2, 3, 4 and 5 in 2015, Duke Indiana will have a need for capacity, which is exacerbated if Duke Indiana also decides to retire Wabash River Unit 6. Ms. Armstrong testified that replacing this lost capacity with gas generation ensures that the capacity shortfall is met without adding any additional SO_2 emissions to Duke Indiana's portfolio. She also noted that although Vermillion does not receive many allowances under CSAPR, the allowances it does receive are enough to meet the facility's current emissions. When comparing the two options for replacing capacity from the retirement of Wabash River Units 2 through 5, Ms. Armstrong testified that with the Consent Decree restrictions on the use of Gallagher SO2 allowances, she's not convinced that the Gallagher Conversion Project would be much more advantageous than the Vermilion acquisition as far as compliance with CSAPR compliance is concerned. Ms. Armstrong further testified that although unlikely, if the EPA were to regulate Coal Combustion Residuals (CCRs) as hazardous waste, the costs to electric utilities would be much greater with more stringent requirements. As natural gas does not generate large quantities of ash as coal-fired generation does, a facility could avoid the complexities and costs of CCR regulations if it uses natural gas for electric generation.

In summary, Ms. Armstrong stated that the OUCC supports Duke Indiana's request to purchase the Vermillion facility. However, the OUCC maintains that converting Gallagher Units 1 and 3 to gas-fired units is not a viable option even if the Vermillion acquisition falls through, as further discussed by Mr. Alvarez. In addition, Ms. Armstrong recommended denial of recovery of the costs associated with the surrender of EAs through Rider 63, and opposed any recovery of these expenses (estimated at $7.2 million) in rates.

Mr. Wes R. Blakley, a Senior Utility Analyst for the OUCC, addressed Duke Indiana's request for authority to record a deferral for post transaction/post-in service carrying costs and depreciation costs associated with the Vermillion purchase as well as Duke Indiana's request to establish a regulatory asset for the net book value for Gallagher Units 1 and 3. Mr. Blakley 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, thus providing financial statement relief until the time the assets can be included in base rates and begin recovering a return on the asset and a return 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 noted that Duke Indiana's witness Kent K. Freeman estimated that Petitioner will experience annualized jurisdictional earnings erosion after tax of approximately $5.2 million until the conclusion of the next base rate case.

Mr. Blakley noted 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, Utility Center Inc., the Commission stated that utilities request and receive post-in-service rate making treatment to avoid earnings erosion that may result from significant and new interest and depreciation expenses. Mr. Blakley stated that the Utility Center order makes it clear that utilities must show that, even when they have costs that may be eligible for capitalization as a regulatory asset for future recovery in rates per Generally Accepted Accounting Principles ("GAAP"), they must still provide evidence that without this special authorization, they would incur material earnings erosion. He added that the Commission also made it clear that earnings erosion should be viewed in the context of the utility's operations as a whole.

Mr. Blakley opined that Duke Indiana did not provide strong evidence of earnings erosion. He acknowledged that Duke Indiana did include an estimate in testimony that there was approximately $5.2 million of annual earnings erosion after tax until the next rate case, but noted the supporting evidence for that number is not clear. In addition, Mr. Blakley stated that Duke Indiana did not estimate how long the earnings erosion would last. Mr. Blakley indicated that Duke Indiana's earnings erosion estimate must be viewed in the context of the operation as a whole comparing the estimated after-tax earnings erosion of $5.2 million with Duke Indiana's total after-tax income. He explained that the result would show how material the earnings erosion estimate is on an annual basis. Mr. Blakley noted that Page 114, line 26, of Duke Indiana's FERC Form 1 shows approximately $384 million of Net Utility Operating Income for 2010. Thus, the earnings erosion that Petitioner estimates is about 1.35% of Petitioner's 2010 Net Utility Operating Income. Mr. Blakley noted the cost of Petitioner's share of the Vermillion plant is estimated at $68 million without AFUDC, and the total net book value of Petitioner's utility plant is $7.3 billion as of December 31, 2010 as shown on page 110 line 14, of FERC Form 1. Thus, he noted, the percentage that the Vermillion purchase represents of Petitioner's net assets is .93% (68 million/7.3 billion =.0093) or less than 1%.

Mr. Blakley testified that in determining whether a specific project may cause significant and material earnings erosion the Commission has in other cases compared percentage of earnings erosion with the percentage of total company earnings. He added that the Commission has also considered the percentage a project represents of the total net utility plant.

Mr. Blakley noted that in Cause No. 39150, the Commission concluded "the cessation of AFUDC and the commencement of depreciation on the two previously described projects would have a significant adverse effect on Petitioner's financial condition." Mr. Blakley explained that in Cause No. 39150, the Commission noted significant pre-tax earnings erosion of 25% company-wide. He added that the Commission in that case also noted the project cost was 13.3% of total company net utility plant.

Mr. Blakley asserted that when a utility requests post-in-service accounting treatment, it must: (1) demonstrate that it will experience material earnings erosion; (2) quantify this erosion as a percentage of total company earnings; and (3) display the cost of the project or purchase as a percentage of net utility plant. Mr. Blakley added that while it is within the purview of the Commission to ultimately decide whether the evidence establishes material earnings erosion that will negatively impact Petitioner financially, he did not believe Duke Indiana's claimed earnings erosion was sufficiently material to warrant the special accounting relief it seeks.

As to the Company's request to establish a regulatory asset for the net book value for Gallagher Units 1 and 3, Mr. Blakley testified that it makes no sense to create a regulatory asset to enable further recovery of costs associated with a plant that may not be used and useful at the time of Duke Indiana's next rate case. He stated that because revenue requirements associated with Gallagher are already embedded in Duke Indiana's base rates, the proposal is unreasonable and must be rejected. He testified that during the approximately 50 years the plant has been in service, Duke Indiana has earned a return on and has recovered depreciation expenses on this plant. Mr. Blakley testified that Gallagher is being retired near the end of its useful life, and the proper accounting entries would be to credit the plant account for the original cost and debit accumulated depreciation for the original cost. In addition, he stated that demolition costs would be debited to the reserve and any salvage value credited to the reserve. Mr. Blakley stated that he knows of no instance where a utility would have to charge an expense account for an ordinary retirement. In addition, he stated that Duke Indiana's base rates will continue to include revenue requirements (established during the last rate case) related to return on and return of Gallagher investment as well as non-fuel operating expenses. Mr. Blakley recommended that the proposed creation of a regulatory asset related to Gallagher should be denied.

Mr. Blakley testified that the Company's request to record as a regulatory asset the construction costs of the Gallagher gas conversion project should be denied based on the lack of earnings erosion impact. Mr. Blakley asserted that the question of the recovery of the actual costs spent through 2011 on the Gallagher gas conversion project should be decided in Duke Indiana's next base rate case.

9. **Industrial Group's Evidence.** Mr. James R. Dauphinais, consultant and principal of Brubaker & Associates, Inc., testified that the Industrial Group does not oppose the granting of a CPCN for the Vermillion purchase. However, he testified that the Industrial Group objects to the deferral of the depreciation expense on the purchase of Vermillion pending inclusion of the purchase cost in base rates, as Duke Indiana has not shown that the alleged $5.2 million earnings erosion will cause an extraordinary impact to the Company's earnings. If the Commission were to consider any deferral, Mr. Dauphinais testified that Duke Indiana's proposed use of its AFUDC rate for the carrying costs of the deferred expense is inappropriate and that instead, Duke Indiana's cost of short-term debt should be utilized as it is likely the Company will utilize short-term borrowing to cover the deferred depreciation expense. If the Commission decided to grant the requested deferral, the Industrial Group also recommended that a sunset be placed on the deferral of no later than June 30, 2013; that Duke Indiana begin amortization of the deferred amount beginning no later than July 2013 with that amortization period being no less than five years; and a limit on the carrying costs to the Company's short-term debt rate. He testified that as a result, it would help minimize the adverse impact on ratepayers of the single issue ratemaking that would be introduced by the granting of the deferral.

Mr. Dauphinais opposed Duke Indiana's request to recover the net book value associated with Gallagher Units 1 and 3 if they are retired due to completion of the Vermillion purchase. He testified that Duke Indiana's current base rates include this recovery; therefore, there is no need to establish a regulatory asset at this time. As a result, he stated that special treatment of the remaining net book value does not need to be addressed until the Company's next rate case. Mr. Dauphinais testified that the Industrial Group does not oppose the Company seeking to recover the prudently incurred costs associated with keeping the option of the Gallagher Gas Conversion available as an alternative to the Vermillion purchase through the end of 2011 in a future base rate proceeding. However, he opposed the creation of a regulatory asset for these costs and instead recommended that these costs be booked as capital additions to Gallagher Units 1 and 3 for recovery in Duke Indiana's next rate case.

Mr. Dauphinais testified that the Industrial Group opposes the granting of an unconditional CPCN for the natural gas conversion of Gallagher Units 1 and 3 because Duke Indiana did not show it is a more economic alternative to the Vermillion purchase. However, the Industrial Group did not oppose a CPCN being granted on the condition that it only applies if the Vermillion purchase fails to close. He explained that it would not be appropriate to grant an unconditional CPCN for the Gallagher Conversion until reasonable evidence has been presented showing it is appropriate for Duke Indiana to complete both the Vermillion purchase and the Gallagher Gas Conversion.

Mr. Dauphinais stated that, for the same reasons cited in opposition to Duke Indiana's other deferral requests, the Industrial Group opposes a deferral for the depreciation expense for the Gallagher Units 1 and 3 gas conversion if it is completed Mr. Dauphinas recommended that the same three conditions be placed on any deferral for Gallagher as he recommended with regard to Vermillion.

10. <u>Duke Indiana's Rebuttal Evidence</u>. Duke Indiana offered the rebuttal testimony of Mr. Roebel, who responded to the testimony and recommendations of the OUCC. Mr. Roebel testified that all actions related to the Gallagher pulverizer replacements, from the initial replacements through the decision to enter into the Consent Decree, were made only after a thorough economic analysis was performed to help the Company make robust and appropriate choices on behalf of customers. He stated that with so many electric utilities in the same situation as Duke Indiana, it should be apparent that Duke Indiana's replacement of its Gallagher pulverizers was reasonable based on what it knew or reasonably should have known at the time the projects were executed. He further testified that this was not a typical case where one could easily conclude that the rules were clearly known, communicated by the government or understood.

Mr. Roebel testified that the basis of the jury's liability verdict on the pulverizer replacements at Gallagher was the EPA's reliance upon testimony at trial from expert witnesses who had developed an NSR methodology based on "availability improvement projects" and projecting a reduction of historic forced outages attributed to the replaced components. He stated that this same methodology was later rejected by the Seventh Circuit Court of Appeals for the Wabash River units, however, at the time of the Gallagher case, Duke Indiana did not yet know that its Wabash River appeal would be successful. Therefore, the Company determined to seek a settlement of the Gallagher issues rather than file a second appeal. In addition, he stated that the settlement was appealing since the Company believed the District Court Judge would likely order Gallagher Units 1 and 3 to be shut down soon after the issuance of a remedy order and remain shut down during the pendency of the appeal, as were the Wabash River Units.

In response to Ms. Armstrong's testimony that Duke Indiana's request to recover approximately $6 million relating to the Gallagher EAs is unreasonable because courts have already decided the issue and the Commission does not have jurisdiction to judge whether or not the Clean Air Act applied to the Gallagher pulverizer replacements, Mr. Roebel testified that Duke Indiana is not seeking any such determinations from the Commission. He went on to state that for the Commission to find that it is reasonable and appropriate for Duke Indiana to recover such costs, it must find that the Company's overall actions with respect to the Consent Decree as a whole were reasonable. He stated that subsumed in that, the Commission must also conclude that the Company's actions with respect to the Gallagher pulverizer replacements were not unreasonable given what the Company knew or should reasonably have known at the time those actions were taken. Mr. Roebel testified that to make such a determination does not require the Commission to inappropriately intercede in or "second guess" the NSR litigation that continues in the court today. Rather, the Commission must examine all the circumstances that existed at the time and determine whether the Company's actions with respect to the Gallagher pulverizers and the Consent Decree as a whole are reasonable such that the EA surrender costs should be recoverable through rates.

In response to Ms. Armstrong's testimony that Duke Indiana should not be permitted to recover costs associated with the Gallagher EA surrenders on the grounds that it would be "unfair" for customers to pay for "legal violations and flawed business decisions," Mr. Roebel testified that it would not be in the best interest of customers or good policy for the Commission to focus only on the jury verdict and ignore the majority of the Company's decisions relating to the Gallagher pulverizer replacements. He stated that the Commission's job is to balance the interest of utilities' customers and shareholders – not necessarily to ensure environmental compliance at any cost. Mr. Roebel testified that the Commission should maintain the traditional model of cost recovery understood by its regulated utilities – no cost recovery for penalties, but consideration of cost recovery for other aspects when overall prudence has been supported by the evidence in a regulatory proceeding. Mr. Roebel testified that Duke Indiana has provided evidence that its business decisions were not "flawed" and its actions have benefited customers by: (1) initially undertaking the underlying projects, which improved reliability of its units and reduced costs to customers under a reasonable belief that Duke Indiana was complying with the law based on the facts and circumstances known or reasonably knowable at the time; (2) vigorously defending its actions relating to the underlying projects in the NSR litigation by successfully winnowing down the 165 original claims to just two on which a finding of liability was made; (3) reaching a reasonable settlement that resolved all potential future litigation relating to the identical pulverizer replacements on Gallagher Units 2 and 4, and eliminated the risks of an immediate court-ordered shut down of Gallagher Units 1 and 3; (4) successfully appealing the District Court's decision which resulted in resumed operation of Wabash River Units 2, 3, and 5; and (5) saving customers $8 billion by not installing best available control technology at the time of the underlying projects. Mr. Roebel testified that Duke Indiana and EPA negotiated and reached agreement on the EA surrenders using the same formula applied in the Wabash River Remedy Order.

Mr. Roebel testified that there was no evidence presented or facts to even suggest that Duke Indiana intentionally negotiated for more expensive mitigation projects and less civil penalties in its Consent Decree, as Ms. Armstrong speculated. He stated that the civil penalties agreed to were the result of arm's length negotiation with the Government attorneys, and ultimately found to be reasonable by the District Court Judge who approved the Consent Decree.

In response to Ms. Armstrong's suggestion that Duke Indiana could have asked the EPA to evaluate the pulverizer project and make a determination whether or not NSR would apply, Mr. Roebel responded that based upon what the Company knew at the time, it did not believe a permit was required. He further stated that even if Duke Indiana had sought a pre-determination from an environmental agency, such applicability finding would not be binding on the EPA, as demonstrated in *U.S. v. S. Ind. Gas & Elec. Co.*, 2002 U.S. Dist. LEXIS 14039 (S.D. Ind. 2002).

Mr. Roebel responded to the issues raised by Mr. Alvarez regarding the Vermillion Units. In response to Mr. Alvarez's statement that the heat rate for the Vermillion Units is 18% more than the manufacturer's performance specification, Mr. Roebel explained that the manufacturer's performance specification cited by Mr. Alvarez is at ISO conditions and that it is unlikely that a peaking plant would operate in Indiana under ISO conditions. He stated that the heat rate for the Vermillion Units is consistent with what would be expected given that these units typically run at no more than 60% load. In response to Mr. Alvarez's concerns regarding a "restricted flow rate" on one of the gas supply laterals serving the Vermillion Plant, Mr. Roebel testified that this was a secondary line installed during start-up with only enough capacity for four units, as it was used for initial commissioning only. He testified that there are no issues with an adequate supply of gas via the main line and that the existence of this second gas line should be viewed as an asset. As to Mr. Alvarez's testimony that the Vermillion Plant is neither fast-start-fast-load nor black start capable, Mr. Roebel testified that fast start capability could be added to all eight units, but it would require a more substantial investment to upgrade the auxiliary power systems. Similarly, black start capability could be enabled, with additional investments. Mr. Roebel testified that the historical low capacity factor of the Vermillion Plant is entirely expected and reflects its proper role in the generation mix in the Midwest ISO region.

In response to Ms. Armstrong's statement that Duke Indiana did not adequately support its position that the Gallagher pulverizer replacements should not have triggered NSR or PSD regulations, Mr. Pearl testified that the Duke Energy environmental team reviewed all aspects of the potentially applicable environmental rules and regulations to determine what, if any, permits or compliance measures might be required. He testified that they concluded that the Gallagher pulverizer replacement project did not trigger NSR because the projects were expected to reduce SO_2 emissions, opacity and particulate emissions, and were essentially like-kind replacements that would not increase hourly emissions or reach the 50% replacement threshold. He stated that the team based its conclusion on past involvement in reviewing pulverizer replacement projects, familiarity with the environmental rules and regulations, and past experience in the environmental department. Mr. Pearl testified that Duke Indiana's conclusion was reasonable based on what they knew or should have known at the time. Mr. Pearl disagreed with Ms. Armstrong's suggestion that the Company should have sought an applicability determination on whether the Gallagher pulverizer replacement projects triggered NSR.

Dr. Richard Stevie testified in response to Mr. Alvarez's claim that the Company overstated its projected annual peak load growth rate in its load forecast. Dr. Stevie testified that Mr. Alvarez used incorrect data, ignored the relationship between changes in the economy and its impact on load growth, and that the Company's forecast was not overstated when compared to the SUFG's projected growth rates for 2011-2014. Dr. Stevie further testified that Mr. Alvarez's allegation that Duke Indiana's projected peak load growth rate from 2011 to 2014 counter balanced the additions of the Vermilion Plant and the IGCC, reflected a fundamental misunderstanding of the forecasting and resource planning process. Dr. Stevie testified in response to Mr. Alvarez's allegation that Duke Indiana pushed up its load forecast in the early years to justify plant additions and then subsequently reduced it once the plant additions were made to get it back to a more reasonable trend. Dr. Stevie explained that Duke Indiana's load forecast is the sum of both retail and wholesale projected loads. He stated that the parallel changes to both load and capacity resulted in only a minor impact to the reserve margin in that Duke Indiana is no longer required to carry the reserves to backstand Wabash Valley's and IMPA's shares of Gibson 5. He stated that this loss of wholesale load is why the forecasted growth rate is -3.61% in 2015, and is not an artificial move by the Company to get the forecast back close to the 2012 level. Dr. Stevie also testified that Mr. Alvarez's approach to smooth out the Duke Indiana forecast is invalid because: (1) in doing so, such a smoothed-out forecast would ignore the drop in load expected in 2015 with the end of the Gibson 5 backstand agreements; and (2) the use of a long-term growth rate to forecast load completely ignores the impact of projected changes in the economy, which must be incorporated to prepare a credible load forecast. Dr. Stevie testified that Mr. Alvarez's use of a long-term trend growth rate does not capture the impact that near-term changes in the economy can have on energy use, which is one reason a long-term trend growth rate to prepare a load forecast is not a widely-used methodology.

Mr. Keith Pike responded to the testimony of Ms. Armstrong regarding new environmental regulations, the potential impact on Duke Indiana's generating units, and the implications of that to the Gallagher Gas Conversion project. Mr. Pike testified that he basically agreed with Ms. Armstrong's representation of the history, regulatory structure, and potential compliance options, although some areas of her testimony were generalized and did not necessarily capture or reflect some of the nuances of the rules. He also discussed other pending regulations that Ms. Armstrong did not discuss that Duke Indiana is taking into consideration. Mr. Pike testified that absent the Gallagher Consent Decree, these regulations would likely have prompted the emission reductions imposed by the Consent Decree anyway. He further testified that to dismiss the Gallagher gas conversion option at this point in time, even as a "plan B," ignores the potential value of this capacity in a future capacity constrained situation. He stated that the approximately \$263/kW for the Gallagher conversion today may still be much lower cost than other options in the future. Mr. Pike testified that Duke Indiana's actions related to the Consent Decree were quite prudent, were made to benefit customers, and should be reasonable for the Company to recover the costs that remain.

Mr. Danny Wiles, General Manager, U.S. Franchised Electric & Gas Accounting, Duke Energy Business Services LLC, provided rebuttal testimony regarding opposition to the creation of a regulatory asset for the remaining net book value associated with Gallagher Units 1 and 3. Mr. Wiles testified that both Duke Indiana's proposal and the proposals of Mr. Dauphinais and Mr. Blakley would have similar results for customers, as the Company would continue to recover the cost of the units from customers under all proposals. He stated that the only difference is an accounting distinction whereby the recovery would be via amortization of a regulatory asset under the Company's proposal rather than depreciation of the cost of the units maintained in property accounts. He explained that the Company is not requesting a rate change at this time associated with the regulatory asset, and even at the time of the next base rate case there should be no appreciable rate impact associated with this proposal. Mr. Wiles testified that because the retirement of Gallagher Units 1 and 3 would not be considered to represent "normal" retirements for accounting purposes, the accounting rules would not allow Duke Indiana to leave the net book value of Units 1 and 3 in the property accounts once the units are retired. He explained that although the intent of the OUCC and the Industrial Group is to accomplish the same result as Duke Indiana's proposal, as a practical matter, their proposals to not allow Duke Indiana to establish a regulatory asset would require an immediate write-off, which would be inconsistent with the result of Duke Indiana's proposal and that of the OUCC and Industrial Group.

Mr. Wiles testified that the Company would not be "double-recovering," as implied by the OUCC and Industrial Group as Duke Indiana has not requested the deferral of carrying costs on the regulatory asset or of depreciation or amortization of the regulatory asset for the specific reason that the assets are currently being recovered in base rates and in the Company's Riders 62 and 71. He explained that under the Company's proposal, the only change is *the account* in which the net book value will be recorded and *the account* in which the amortization of the costs, which will take the place of depreciation, will be recorded – there is no deferral request for depreciation or amortization, request for accrual of carrying charges on the regulatory asset until the next rate case, or impact on retail rates. He testified that the Company would simply transfer the remaining net book value of Gallagher Units 1 and 3 from the property accounts to a regulatory asset account, and begin amortizing the regulatory asset over the remaining life of the Gallagher Units 1 and 3 rather than continuing to reflect depreciation. Mr. Wiles testified that from a ratemaking perspective, at the time of the next rate case, the net book value of the regulatory asset will be less than the amount initially recorded at the time of the transfer due to amortization booked until that time, similar to how the net book value of the plant, if it had not been retired or if the Company were able to leave it in the property accounts, would be less due to additional accumulated depreciation, thereby ensuring no double recovery of the costs.

Mr. Wiles responded to the Industrial Group's proposal that if the Commission approves carrying costs and deferred depreciation expense that the rate applied to such costs should be at the Company's short-term debt rate and not the Company's AFUDC rate as proposed by Duke Indiana. Mr. Wiles stated that the Company does not specifically apply financing to a particular project and Duke Indiana's AFUDC rate calculation assumes the Company's short-term debt is applied to construction work in progress. He testified that in fact, if short-term debt was specifically assigned to the Vermillion project, it would not be appropriate to also include the same short-term debt in the calculation of AFUDC, which would result in higher AFUDC rates for other projects.

Mr. Kent Freeman testified to the totality of the earnings erosion that could take place if the Company's request for deferred accounting were not granted. He explained that Duke Indiana would experience approximately \$5.2 million each year in after tax earnings erosion from the Vermillion purchase for post-in-service carrying costs and post-in-service depreciation expenses, and would incur after tax earnings erosion of approximately \$3.7 million associated with the gas conversion costs, or a total of approximately \$8.9 million. He stated that although this may not create a financial emergency, it is by no means insignificant for Duke Indiana. Mr. Freeman testified that other factors should be considered when determining if costs should be deferred, including the matching of costs and revenues. He explained that without approval of the deferral, the Vermillion Plant will be providing service to customers with no cost recovery by Duke Indiana. Further, post-in-service deferred accounting treatment recognizes the lag between the in-service date of a new facility and the effective date of new rates. He stated that this is a longstanding and well-accepted regulatory practice used to mitigate adverse earnings erosion that would otherwise result from the utility making needed investments that are used and useful in providing service to customers prior to the date when those investments are included in rates. Mr. Freeman noted the Commission's Order in Cause 42469 in which the Commission approved deferred accounting treatment, stating that maintenance of credit quality is important for both the utility and the customers. Mr. Freeman testified that the Company continues to have significant financing requirements which will likely continue with pending and impending environmental regulations. Thus, the Commission's points regarding financing requirements and credit quality in Cause 42469 are still fully applicable today.

Mr. Freeman stated that Duke Indiana would be agreeable to stopping the deferral at the earlier of June 30, 2013, or the effective date of new rates pursuant to the Company's next retail base rate order. In addition, Duke Indiana is agreeable to starting amortization of the deferred gas conversion costs at the earlier of July 2013, or the effective date of new rates pursuant to the Company's next retail base rate order and amortizing such costs over a five-year period. He testified that the deferral amount related to the Vermillion Plant would be amortized, starting no later than July 2013, over the remaining life of the plant – approximately 27 years as of July 2013. Mr. Freeman noted that a limited deferral period is consistent with the settlement agreement approved by the Commission in the Company's purchase of the Wheatland Plant, Cause No. 42469.

11. Commission Discussion and Findings.

A. Duke Indiana. In this proceeding, Duke Indiana seeks a CPCN to purchase a portion of the Vermillion generating station or, in the alternative, to convert Gallagher Units 1 and 3 from coal-fired to natural gas-fired generation units.

This case contains issues that generally related to the result of decades-long litigation between Duke Indiana, the EPA and certain other plaintiffs as a result of the NSR litigation discussed above. Duke Indiana ultimately decided to enter into a Consent Decree with the EPA, under which it committed to take certain actions with regard to its Gallagher Units. The Consent Decree required Duke Indiana to install the dry sorbent injection system ("DSI") at Gallagher Units 2 and 4. Duke Indiana also committed to either convert Gallagher Units 1 and 3 to gas-fired boilers or retire those units. In addition Duke Energy Indiana agreed to surrender certain emissions allowances.

Here, Duke Indiana originally sought a CPCN to convert Gallagher Units 1 and 3 to gas-fired boilers. However, during the course of this proceeding, Duke Indiana became aware of the opportunity to purchase a portion of the Vermillion generating station, and modified its Petition to request a CPCN to complete the purchase. Because we approve Duke Indiana's request for a CPCN to purchase a portion of the Vermillion plant, we need not address its request for a CPCN to convert the Gallagher Units to gas-fired generation.

1. Vermillion Purchase. A public utility may not begin construction, purchase, or lease of any facility for the generation of electricity without first obtaining a CPCN from the Commission. Ind. Code § 8-1-8.5-2. Ind. Code ch. 8-1-8.5 prescribes matters the Commission must consider in ruling on a request for a CPCN. Indiana Code § 8-1-2.5-5 ("Section 5") requires the Commission to hold a public hearing on the application for the CPCN and allows the Commission to grant the request if the Commission makes findings (1) as to the estimated construction, purchase, or lease costs; (2) that either such construction, purchase, or lease will be consistent with the Commission's plan for expansion of electric generation capacity, or that the construction, purchase or lease will be consistent with a utility specific proposal as to the future needs for electricity to serve the people of the state or the area served by the utility; and (3) that the public convenience and necessity require or will require the construction, purchase or lease of the facility. Indiana Code § 8-1-8.5-4 ("Section 4") provides the Commission shall take into account various arrangements and alternatives for providing electric service. We conducted a public hearing on September 26, 2011 which satisfied the procedural requirements of Section 5.

Based on the evidence presented, the Commission finds that the requirements of Ind. Code ch. 8-1-8.5 have been satisfied. No party to this proceeding opposed the issuance of a CPCN for the Vermillion purchase. The Commission finds, based on the testimony in this cause, that Duke Energy Indiana's negotiated purchase price for its overall 62.5% share of the Vermillion facility is $68 million, excluding carrying costs and transaction costs. Duke Energy Indiana's plan to purchase the Vermillion generating station is consistent with the utility's proposal as to the future needs for electricity in its service territory. Duke Energy Indiana witness Hager discussed the factors that are required to be considered under Ind. Code § 8-1-8.5-4 with respect to the purchase of 400 MW of Vermillion capacity. Accordingly, based on the evidence submitted in this Cause and the findings set out in this Order, the Commission finds that public convenience and necessity require Duke Energy Indiana's purchase of a 62.5% undivided ownership interest in the Vermillion Generating Facility, and conclude that a CPCN should be granted to Duke Energy Indiana for such acquisition pursuant to Ind. Code § 8-1-8.5-2.

We note that the purchase transaction is not final (and could not be final without this Order). However, with the issuance of this Order, Duke Indiana should have all required authorization to proceed with the transaction. Accordingly, Duke Indiana is ordered to notify the Commission within five (5) business days after the Vermillion purchase transaction closes.

2. <u>Deferred Accounting and Regulatory Assets</u>. Duke Indiana requested authority to defer for subsequent recovery depreciation and post in service carrying costs at its AFUDC rate for the Vermillion plant and transaction related costs, until such costs are reflected in Duke Indiana's retail electric rate base; recovery of the remaining net book value for Gallagher Units 1 and 3 if those units are retired, through creation of a regulatory asset and accounting for dismantling costs through normal removal accounting; approval to create a regulatory asset and to recover such asset with carrying costs for costs incurred to pursue the Gallagher gas conversion project and keeping that option, Plan B open through the end of 2011. Mr. Esamann explained that without the approval of this requested relief, Duke Indiana would experience material earnings erosion, up to as much as $60 million in 2012. The overwhelming majority of this earnings impact would be associated with the remaining net book value for Gallagher Units 1 and 3.

The OUCC and the Industrial Group opposed the creation of a regulatory asset for the remaining book value of Gallagher Units 1 and 3 in the event that the Vermillion purchase is completed and those units are retired, on the grounds that Duke Indiana was recovering the costs associated with these two units in rates. In rebuttal, Mr. Wiles explained that the retirement of these units, if it occurs at the end of 2011, would not be considered "normal" under generally accepted accounting principles ("GAAP"), since for depreciation purposes, the retirements for these units are estimated to occur in the 2019-2020 time period. Mr. Wiles also explained that there would be no "double recovery" since Duke Indiana is not now requesting that amortization of the regulatory asset begin and had not asked for carrying costs on this regulatory asset. Rather, revenues for depreciation of these units, which are currently included in rates, would be used to offset the value of the regulatory asset until Duke Indiana's next base rate case when the Company would request amortization of the regulatory asset over what would have been the remaining lives of the units.

The OUCC and the Industrial Group also opposed Duke Indiana's requests for deferral and later recovery of: depreciation and post in service carrying costs at its AFUDC rate for the Vermillion plant and transaction related costs; costs incurred to pursue the Gallagher gas conversion project; and costs related to keeping that option open. The OUCC and Industrial Group argue that any earnings erosion incurred by Duke Indiana from the above costs would not cause an extraordinary or material impact on the Company's earnings. Mr. Dauphinais also recommended that if such regulatory assets were created, the carrying costs should be calculated using the Company's short-term debt rate rather than the AFUDC rate and that the Commission should place a "sunset" on any such deferrals.

Mr. Wiles explained that using the Company's short term-debt rate for carrying costs, as proposed by Mr. Dauphinais, would not be appropriate, because the Company does not specifically apply financing to a project and that, if this recommendation were to be followed, it would not be appropriate to include the same short-term debt from the calculation of AFUDC, which would result in higher AFUDC rates for other projects.

Mr. Freeman explained in rebuttal that the earnings erosion impacts needed to be considered in totality, and that the Company would experience earnings erosion of approximately $8.9 million annually from the Plan B preservation costs and the Vermillion post acquisition costs (while customers would get the benefit of service from the Vermillion facility). In Mr. Freeman's opinion this amount is not insignificant. Mr. Freeman also agreed with Mr. Dauphinais that a "sunset" provision would be appropriate. In its September 23, 2011 response to the Commission's September 20, 2011 Docket Entry, Duke Indiana offered to include the "Plan B" preservation costs with the Gallagher Units 1 and 3 remaining net value regulatory asset and to amortize this regulatory asset over 14 years in order to mitigate the impact on customers.

In regard to the remaining net book value of Gallagher Units 1 and 3, there is no question that these units have been used and useful in providing service to Duke Indiana's customers for approximately 50 years. In addition, Mr. Wiles explained the accounting necessity for the requested authority and explained that there will be no impact on customers. We therefore find that Duke Indiana's request to create a regulatory asset for the remaining net book value of Gallagher Units 1 and 3 is reasonable and should be approved.

In regard to the gas conversion costs already incurred, Duke Indiana stated in its September 23, 2011 response to the Commission's September 20, 2011 Docket Entry that it could include the gas conversion costs with the net book value in one regulatory asset and amortize it over 14 years. It also stated doing so would be in compliance with Generally Accepted Accounting Principles. The Commission prefers this alternative, as opposed to what Duke Indiana originally proposed in relation to these costs, in order to mitigate the impact on customers and limit the number of Duke Indiana's regulatory assets. Therefore, the Commission grants Duke Indiana authority to include the gas conversion costs with the net book value in one regulatory asset and amortize it over 14 years.

In regard to the purchase of the Vermillion Plant, Duke Indiana identified approximately $2.4 million of net operating income (NOI) attributable to its investment in Gallagher Units 1 and 3 is included in its base rates pursuant to Cause No. 42359 (an additional $2.7 million of NOI attributable to Gallagher Units 1 and 3 is included in Duke Indiana's Rider 62). Accordingly, Duke Indiana will continue to have rates in place that are designed to earn the return on its Gallagher units 1 and 3 granted in Cause No. 42359 until its rates are updated pursuant to a final Commission order in the company's next rate case. This will partially offset the earnings erosions that Duke states it will experience due to its purchase of the Vermillion plant; the Commission therefore finds that any earnings erosion due to the purchase of Vermillion are not significant enough to warrant the requested accounting treatment in relation to Vermillion, and denies Duke Indiana's request to defer for subsequent recovery the depreciation and post in service carrying costs for the Vermillion plant and transaction related costs.

3. DSI System. In our Order in Cause No. 43873, we granted a CPCN to Duke Indiana for the use of the proposed DSI System and approved the estimated cost for that system. In that Order, we found that Duke Indiana adequately demonstrated the need for the DSI System on Gallagher Units 2 and 4 and that the DSI System will assist the Company in complying with possible future environmental requirements related to SO_2 emissions. However, we deferred any decision with respect to Duke Indiana's recovery of the costs associated with the DSI System pending the results of this proceeding.

In this proceeding, Duke Indiana requests authority to include the DSI System in its Qualified Pollution Control Property ("QPCP") and to recover a return on the capital expenditures for the DSI System pursuant to Rider No. 62 and to recover the incremental O&M expenses (including the cost of reagents and depreciation) of the DSI System pursuant to Rider No. 71.

In Cause No. 43873, the Commission held the DSI System constituted "clean coal technology" pursuant to Ind. Code ch. 8-1-8.7 and granted Duke Indiana a CPCN for use of the proposed DSI system. Therefore in accordance with the provisions outlined in Ind. Code § 8-1-8.8-11(a)(1), we approve Duke Indiana's request to include the capital – up to a cap of $16.6 million, the estimated cost approved in Cause No. 43873 – and other costs associated with the DSI System in Duke Energy Indiana's next Rider 62 and Rider 71 proceedings.

4. Emission Allowance Surrender. Duke Indiana also requested permission to recover in rates the book value of the EAs it has surrendered or will surrender as a result of the Consent Decree pursuant to Duke Energy Indiana's Standard Contract Rider No. 63-SO_2, NO_x and Hg Emission Allowance Adjustment ("Rider 63") and Standard Contract Rider No. 70-Summer Reliability Adjustment ("Rider 70"). In support of its request, Duke Indiana asserts that: (1) Duke Indiana, as well as other utilities, reasonably believed its actions were not in violation of EPA rules; (2) there is no evidence that Duke Indiana negotiated EA surrenders in exchange for a lower civil penalty; (3) the Commission should disregard the OUCC's contention that the EA surrenders are unrelated to providing electric service; and (4) Duke Indiana's customers have benefitted from the low cost energy produced by the Gallagher units.

The Commission previously addressed emission allowance surrenders pursuant to a NSR Consent Decree in *Indiana Michigan Power Co.*, Cause No. 43992, 2011 Ind. PUC LEXIS 163 (IURC June 22, 2011). There, the Commission stated:

> While a Consent Decree is a court-approved settlement agreement with the federal government resulting in legal obligations with which I&M must comply,

> the decision to enter in the Consent Decree was voluntary. Consequently, if I&M wishes to seek recovery of specific costs incurred as a result of its decision to enter into the Consent Decree, it is incumbent upon I&M to demonstrate that its decision to incur those costs was prudent and that the inclusion of such costs in customer rates is just and reasonable.

Id., at *33. While the circumstances in this case and Cause No. 43992 are not identical, our Order in Cause No. 43992 provides useful guidance for the issues in this proceeding.

First, whether Duke Indiana believed its actions did not violate EPA rules and whether such belief was reasonable does not make Duke Indiana's customers responsible for the economic consequence of all costs it consented to pay, including the required EA surrenders. It is Duke Indiana's responsibility, not its customers, to provide utility service that complies with federal law and regulations, and we find that the evidence in this case shows Duke did not. Similarly, it is Duke Indiana's responsibility, and not its customers, to pay the costs that arise solely from its failure to comply with federal law and regulations.

Second, whether or not Duke Indiana negoatiated EA surrenders in exchange for a lower civil penalty is not germane to the issue of the reasonableness of Duke Indiana's recovery of EA surrenders from its rate payers. The Commission views Duke Indiana's EA surrenders as an economic penalty, and we find that Duke Indiana, and not its customers, should pay the costs of its failure to comply with federal law and regulations.

Third, with respect to the OUCC's contention that the EA surrenders are unrelated to providing electric service, Duke Indiana argues that but for Duke Indiana's operations of the Gallagher units for the very purpose of providing electric utility service to its customers, the NSR Litigation and the Consent Decree would not have occurred. We reject this argument. While the Gallagher units were a source of energy used to serve Duke Indiana's customers, it was not the Gallagher units themselves that resulted in Duke Indiana's surrender of the EAs, but rather Duke Indiana's non-compliant operation of those units. If a utility is found guilty of operating a generation unit in violation of EPA regulations and/or federal law, the fact the unit was being operated to provide electric service to the utility's customers at the time does not mean costs resulting from the violation can automatically be recovered from rate payers. Therefore, we agree with the OUCC that the EA surrenders are unrelated to the provision of electric service for ratemaking purposes.

Finally, with respect to Duke Indiana's argument that its customers have benefitted from the low cost energy produced by the Gallagher units, we first note a lack of evidence quantifying such savings or proof that such savings can be said to have flowed to the ratepayers. More importantly, we agree with the sentiments expressed by the OUCC that Duke seeks to avoid the consequence of its violations by making its ratepayers responsible for the EA surrender costs. Petitioner also contends that had it installed the pollution control equipment, which the EPA claimed it should have, at the time of the projects, its customers would have incurred over $8 billion in additional costs. To the extent Duke Indiana means to suggest that the EA surrender expenses due under NSR Consent Decree should be recoverable because Duke Indiana's initial compliance with the law would have been more expensive to rate payers than the result of violating the law, we reject this argument. The economic cost Duke Indiana agreed to accept should be borne by the entity that had the ability to comply with the law as well as the opportunity to most directly accept or reject the requirements imposed by the Consent Decree. Therefore, based upon the evidence discussed above, we deny Duke Indiana's request to recover the book value of the EA surrenders

5. **Fuel.** In Cause No. 38707 FAC 84 ("FAC 84") Duke Indiana was ordered to address the impact of the NSR litigation on fuel costs in a separate proceeding on or before September 30, 2010. Duke Indiana did so in this proceeding. Therefore, as the parties to FAC 84 agreed, this would be the appropriate proceeding for the Industrial Group or the OUCC to raise the issue of the prudence of Duke's actions and inactions prior to the District Court decision ordering Duke Indiana to shutdown Wabash River Station Units 2, 3, and 5 and any related increase in fuel costs, beginning with the fuel costs recovered by Duke Indiana in FAC 84. No party to this proceeding raised the subject of the prudency of increased fuel costs related to the shutdown of Wabash River Station Units 2, 3 and 5 or presented any evidence that such costs were unreasonable. We therefore find that the subject of the prudency of increased fuel costs related to the shutdown of Wabash River Station Units 2, 3, and 5 due to the District Court's NSR Remedy decision should be closed. We further find that the "interim, subject to refund" obligations imposed in our orders in Cause Nos. 38707 FAC 84 through FAC 89 related to this proceeding should be and hereby are removed.

B. Wabash Valley Power.

1. **Vermillion Purchase.** As we noted earlier, Ind. Code ch. 8-1-8.5 governs our review of Wabash Valley's CPCN request to purchase an additional 12.5% of the Vermillion Generating Station.

We find that the evidence presented in this Cause demonstrates that Wabash Valley has made reasonable efforts in its current and potential arrangements with other electric utilities for the interchange of power, pooling of facilities, purchased power and joint ownership of facilities. Wabash Valley has also implemented other methods for providing reliable, efficient, and economic electric service, including the construction of new facilities, conservation, load management, cogeneration and renewable energy sources. The record evidences that Wabash Valley has considered options available to meet increasing demand for electricity and the need for reliable energy and capacity. The record further evidences that the purchase of an additional 12.5% ownership interest in the Vermillion Generating Station is a reliable, efficient, and economic means to meet its needs.

Ind. Code § 8-1-8.5-5 sets forth the specific findings the Commission must make to approve and grant the requested CPCN. First, the Commission must make a finding based on the evidence of record as to the best estimate of purchase costs. Second, the Commission must find that the purchase will be consistent with Wabash Valley's IRP submitted pursuant to Ind. Code § 8-1-8.5-3(e). Third, the Commission must find that the public convenience and necessity will require the facilities for which the CPCN is requested.

Based on the evidence submitted in this Cause and findings set out in this Order, the Commission finds that the cost associated with the purchase of an additional 12.5% ownership interest in the Vermillion Generating Station is reasonable and should be approved and are consistent with Wabash Valley's IRP submitted pursuant to Ind. Code § 8-1-8.5-3(e). We therefore find that based on the evidence submitted in this Cause and the findings set out in this Order that the public convenience and necessity will be served by Wabash Valley's acquisition of the additional 12.5% ownership interest in the Vermillion Generating Station and conclude that a CPCN should be granted to Wabash Valley for such acquisition pursuant to Ind. Code § 8-1-8.5-2.

2. Financing Authority. Ind. Code § 8-1-2-79(a) requires Commission approval of Wabash Valley's issuance of evidence of indebtedness payable more than one year from its issuance and Ind. Code § 8-1-2-84(f) requires Commission approval for the encumbrance of a public utility's property. Wabash Valley's petition and evidence have described the nature and purpose of the long term indebtedness for which it requests approval (i.e., the acquisition of an additional 12.5% ownership interest in the Vermillion Generating Station).

Wabash Valley's evidence demonstrates that it will have sufficient revenue to timely pay the debt without adversely affecting its credit ratings or violating its financing obligation to lenders. Based on the evidence in the record, we find Wabash Valley's request for financing is in the public interest and reasonable and necessary for the operation of the utility. We therefore find that Wabash Valley should be authorized to issue up to $13,600,000 in debt to acquire the additional 12.5% ownership interest in the Vermillion Generating Station and to encumber its property to secure the indebtedness.

C. Duke Vermillion. The record here is uncontroverted that the negotiations that lead to the proposed sale and transfer of the Vermillion Facility were fair, arms length and that the purchase price and terms and conditions of the Facilities Interest Purchase Agreement are fair and reasonable. It is also uncontested that after the proposed transaction is completed Duke Vermillion will no longer own generation assets in Indiana and will have no Indiana public utility attributes. From its inception, the Vermillion Facility has been owned and operated as a merchant plant selling its output into the wholesale market under FERC jurisdiction. Our previous orders have largely declined jurisdiction over the ownership and operation of the Vermillion Facility and imposed limited reporting requirements. Most recently in Cause No. 43965, the Commission continued to decline its jurisdiction over Duke Vermillion and the Vermillion facility, including jurisdiction over "...ownership, operations, accounting, finance, and rates of the Vermillion Facility." *Duke Energy Ohio, Inc.*, Cause No. 43965, 2010 Ind. PUC LEXIS 449, at *15 (IURC Dec. 29, 2010). In addition, on August 12, 2011 in Docket No.EC-11-90-000 the FERC approved Duke Vermillion's proposed sale and Duke Indiana and Wabash Valley's purchase of the Vermillion Facility. Therefore, the Commission hereby confirms its continued declination of jurisdiction over Duke Vermillion's ownership of the Vermillion Facility. As noted above this Commission has approved Duke Indiana's and Wabash Valley's proposed purchase of the Vermillion Facility. The Commission finds that Duke Vermillion has satisfied its obligations to this Commission and upon consummation of the sale and transfer of the Vermillion Facility to Wabash Valley and Duke Indiana, Duke Vermillion will no longer be considered an Indiana public utility and will no longer have any Commission imposed reporting requirements.

12. **Confidential Information.** Duke Indiana filed a *Motion for Protection of Confidential and Proprietary Information* ("Duke Motion") with the Affidavits of Mr. John J. Roebel, Mr. Keith Pike, Ms. Janice D. Hager, and Mr. John P. Griffith on December 14, 2010. In the Duke Motion, Duke Indiana demonstrated a need for confidential treatment for the following: (i) various pricing and operating characteristic information for the Gallagher Conversion Project; (ii) cost estimates for future environmental projects assumed in Duke Indiana's 2009 IRP; (iii) information related to Duke Indiana's 2009 IRP and the updated IRP model runs that were performed for this proceeding; (iv) Duke Indiana's SO_2 and NO_x forecasted EA positions; and (v) specific historical and future cost index data used in Duke Indiana's analysis. In a December 29, 2010 Docket Entry, the Commission preliminarily found that such information should be subject to confidential procedures.

On May 26, 2011, Duke Indiana filed its *Second Motion for Protection of Confidential and Proprietary Information* ("Duke Second Motion") with the Affidavits of Mr. John J. Roebel, Mr. Edwin Keith Bone, Mr. Edward F. Kirschner, and Ms. Diane L. Jenner. In the Duke Second Motion, Duke Indiana demonstrated a need for confidential treatment for the following: (i) certain detail to various pricing, design, technical, and operating information for the Vermillion Generating Station; (ii) insurance premium costs and fuel transportation charges for the Vermillion Generation Station; (iii) potential transmission upgrade costs associated with the retirement of Gallagher Units 1 and 3; and (iv) technical and pricing information regarding The Brattle Group's solicitation results for Duke Indiana's purchase of generating assets. In a June 10, 2011 Docket Entry, the Commission preliminarily found that such information should be subject to confidential procedures.

Wabash Valley filed an *Application for the Commission to Find Certain Information Filed in This Cause as Confidential* ("Wabash Valley Motion") with the Affidavits of Mr. Keith Thompson and Ms. Nisha A. Harke. Wabash Valley demonstrated in its Motion a need for confidential treatment for information critical to the commercial operations of the Vermillion Generating Facility and Wabash Valley's Financial Forecasts. In an August 2, 2011 Docket Entry, the Commission preliminarily found that such information should be subject to confidential procedures.

The Affidavits in support of the Duke Motion, Duke Second Motion, and Wabash Valley Motion indicate that such confidential information has actual or potential independent economic value for Duke Indiana and Wabash Valley and its customers, the disclosure of the confidential information could provide competitors and suppliers an unfair advantage, and Duke Energy and Wabash Valley, and their affiliates, have taken all reasonable steps to protect the confidential information from disclosure. Accordingly, pursuant to Ind. Code §§ 5-14-3-4(a)(4) and 8-1-2-29, we find that the information outlined above are "trade secrets" and should continue to be afforded confidential treatment.

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

Duke Indiana

1. Duke Indiana is granted a Certificate of Public Convenience and Necessity to acquire a 62.5% ownership interest in the Vermillion Generating Station.

2. Without reaching a final decision on the issue, the Commission declines to issue a Certificate of Public Convenience and Necessity for the Gallagher Units 1 and 3 conversion at this time. Duke Indiana shall report to this Commission within 5 business days after the Vermillion Purchase transaction closes. If the transaction does not close, Duke Indiana shall report such circumstances to the Commission within 5 business days and may request issuance of a Certificate of Public Convenience and Necessity for the Gallagher Units 1 and 3 gas conversion at that time.

3. Duke Indiana's request to defer for subsequent recovery the retail jurisdictional portion of depreciation, post-in-service carrying costs (calculated at Duke Indiana's AFUDC rate), and transaction-related costs associated with the purchase of the Vermillion Plant is denied.

4. Duke Indiana is authorized to include in Rider 62 and Rider 71 the investment and the incremental operating costs, including reagent costs and depreciation, associated with the DSI System and is also authorized to defer for subsequent recovery the retail jurisdictional portion of post-in-service carrying costs (calculated at Duke Indiana's AFUDC rate) associated with the DSI System up to $16.6 million.

5. Duke Indiana's request to recover the book value of certain SO_2 emission allowances required to be surrendered by Duke Indiana pursuant to the Consent Decree is denied.

6. Duke Indiana is authorized to defer for subsequent recovery the retail jurisdictional portion of the costs associated with the gas conversion "Plan B" preservation costs through year-end 2011 and shall include such deferrals in the regulatory asset described in Finding Paragraph 6 below.

7. Duke Indiana is authorized to recover the remaining net book value of Gallagher Units 1 and 3 as described in the findings and is authorized to use a regulatory asset for the remaining net book value associated with Gallagher Units 1 and 3 including the preservation costs discussed above amortized over the remaining life of the units, approximately 14 years. Duke Indiana is also authorized to account for dismantling costs through normal removal accounting.

8. Duke Indiana's fuel costs approved in Cause Nos. 38707- FAC84 through the current FAC proceeding related to increased fuel costs as a result of the shutdown of Wabash River Station Units 2, 3 and 5 are no longer subject to refund.

Wabash Valley

9. Wabash Valley is granted a Certificate of Public Convenience and Necessity to acquire an additional 12.5% ownership interest in the Vermillion Generating Station.

10. Wabash Valley is authorized to issue long term debt and execute notes as evidence of indebtedness up to $13,600,000 to acquire the additional 12.5% ownership interest in the Vermillion Generating Station and to encumber its property to secure payment of the indebtedness.

Duke Vermillion

11. The Commission declines jurisdiction over Duke Vermillion II LLC and following the consummation of the proposed sale and transfer of the Vermillion Facility all Commission requirements, including reporting requirements on Duke Vermillion II LLC will terminate.

General

12. All confidential information filed under seal by Duke Indiana and Wabash Valley in this Cause constitute confidential financial and trade secret information and shall continue to be treated by the Commission as confidential and not subject to public disclosure.

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

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

APPROVED: DEC 2 8 2011

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

Sandra K. Gearlds

Sandra K. Gearlds
Acting Secretary to the Commission