ORIGINAL

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF DUKE ENERGY INDIANA, INC., PURSUANT TO I.C. 8-1-2-23 AND 8-1-8.7-1 ET SEQ., (1) FOR ISSUANCE OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR USE OF CLEAN COAL TECHNOLOGY FOR A PROJECT, DRY SORBENT INJECTION, AT PETITIONER'S GALLAGHER GENERATING STATION; AND (2) TO CONDUCT ONGOING REVIEW OF THE IMPLEMENTATION OF THE PROJECT	CAUSE NO. 43873 APPROVED: SEP 0 8 2010

BY THE COMMISSION:
David E. Ziegner, Commissioner
Loraine L. Seyfried, Administrative Law Judge

On March 23, 2010, Duke Energy Indiana, Inc. ("Duke Energy Indiana," "Petitioner" or "Company") filed its Petition and case-in-chief testimony with the Indiana Utility Regulatory Commission ("Commission") for the issuance of a Clean Coal Technology Certificate of Public Convenience and Necessity ("CPCN") pursuant to Ind. Code § 8-1-8.7 for the use of a Dry Sorbent Injection System at its Gallagher Generating Station Units 2 and 4.

On June 9, 2010, the Indiana Office of the Utility Consumer Counselor ("OUCC") filed its direct testimony. Petitioner filed its rebuttal testimony on July 2, 2010. Petitioner also filed on July 28, 2010, a response and confidential attachment to a Docket Entry from the Commission seeking additional detail on the Company's cost estimate and the impact on the Company's proposal of the U.S. Environmental Protection Agency's proposed Clean Air Transport Rule.

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 July 30, 2010, at 9:30 a.m., in Room 222, 101 West Washington Street, Indianapolis, Indiana. Duke Energy Indiana and the OUCC appeared and participated at the hearing.

At the evidentiary hearing, Duke Energy Indiana offered into evidence its case-in-chief testimony in support of its Petition, consisting of the Petition, as corrected,[1] and the testimony and exhibit of Mr. John J. Roebel and Mr. David E. Freeman, as corrected.[2] Duke Energy Indiana also offered into evidence its rebuttal testimony of Mr. John J. Roebel, and Duke Energy

[1] A corrected Petition was filed on July 27, 2010 to reflect a correction to the description of Petitioner's electric generating properties.
[2] The corrected direct testimony of Mr. David E. Freeman was filed on July 27, 2010, to reflect a corrected capacity factor for Gallagher Units 2 and 4 with the proposed Dry Sorbent Injection System.

Indiana's response to the Commission's Docket Entry dated July 23, 2010, and confidential attachment thereto. The OUCC offered into evidence the redacted and unredacted testimony and confidential exhibits of Mr. Anthony A. Alvarez and Ms. Cynthia M. Armstrong. All evidence and exhibits, as corrected, were admitted into the record without objection. Mr. John Roebel provided updated testimony regarding Petitioner's cost estimate, as requested by the Commission in its July 23, 2010 Docket Entry. No members of the general public appeared or participated at the hearing.

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. Duke Energy Indiana is a public utility within the meaning of Ind. Code § 8-1-2-1, as amended, and is subject to the jurisdiction of the Commission in the manner and to the extent provided by the laws of the State of Indiana. The Commission has jurisdiction over Duke Energy Indiana and the subject matter of this Cause.

2. Duke Energy Indiana's Characteristics. Duke Energy 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 Energy 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.

3. Relief Requested in this Cause. Duke Energy Indiana requests that the Commission issue a Clean Coal Technology CPCN pursuant to Ind. Code § 8-1-8.7 to Petitioner for the use of a Dry Sorbent Injection System ("DSI System") at its Gallagher Generating Station Units 2 and 4. Petitioner proposes to seek recovery of the costs related to the Gallagher DSI System via rates or a rate recovery mechanism in a subsequent proceeding.

4. Petitioner's Case-In-Chief. John J. Roebel, Senior Vice President of Generation Support, testified that the DSI System, consisting of storage silos, particle size reduction equipment (*i.e.* mills), feed equipment, piping and injection lances, would reduce sulfur dioxide ("SO_2") emissions from Gallagher Units 2 and 4. He explained that the DSI System injects a sodium-based reagent, most likely either trona or sodium bicarbonate, into the flue gas stream of the units. The reagent reacts with and absorbs SO_2 (and, to a lesser extent, nitrogen oxides ("NO_x")) in the flue gas and is then collected by the units' baghouses. He testified that industry testing has shown that the reagent will also reduce sulfur trioxide ("SO_3"), mercury ("Hg"), and other acid gases, such as hydrogen chloride ("HCl"), to some extent.

Mr. Roebel testified that Duke Energy Indiana has agreed to install and operate the DSI System as part of a Consent Decree entered in the New Source Review ("NSR") litigation, which was initially brought against Petitioner in 1999 by the U.S. Department of Justice ("DOJ"), acting on behalf of the U.S. Environmental Protection Agency ("EPA"), and joined by various citizen groups and states. Mr. Roebel explained that numerous complaints and notices of violation were filed across the country against multiple utilities for alleged violations of the NSR provisions of the Clean Air Act ("CAA"). Generally, EPA alleged that projects performed at various coal-fired units were major modifications, as defined in the CAA, and that 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 particulate matter ("PM"). The complaints sought injunctive relief to require installation of pollution control technology on various generating units that allegedly violated the CAA, and unspecified civil penalties in amounts of up to $32,500 per day for each violation. Mr. Roebel testified that Petitioner believes the projects at its generating stations that were subject to the lawsuit were routine maintenance, repair and replacement activities that were not subject to NSR requirements.

Mr. Roebel testified that of the 165 total claims in the lawsuit against Cinergy Corp., a subsidiary of Duke Energy, 102 claims were specific to Duke Energy Indiana. He stated that the government's allegations involved 34 Indiana projects (each project involved multiple claims for alleged increased emissions) and 14 Indiana generation units. Mr. Roebel testified that prior to trial, Duke Energy Indiana successfully reduced the number of Indiana claims from 102 to 10. The 10 remaining claims involved 8 Indiana projects at 7 Indiana generation units. These claims went to trial and resulted in a May 2008 jury verdict in favor of Duke Energy Indiana on 4 of the 8 projects. The four projects for which the jury found liability were projects on Wabash River Units 2, 3, and 5. Subsequently, the Court ordered a new trial on the 4 projects for which the jury had found in favor of Duke Energy Indiana. Mr. Roebel explained that as a result of this new trial, in May 2009, a jury found liability on the Gallagher Units 1 and 3 pulverizer projects.

Mr. Roebel testified that as a result of the jury verdict and subsequent Court order to shutdown Wabash River Units 2, 3, and 5, these units were placed on a "reserve shutdown" on September 30, 2009. He explained that this means that the units are currently, but not permanently, shut down while the Court's decision is on appeal with the Seventh Circuit. The Company was also ordered to permanently surrender SO_2 emission allowances equal to the SO_2 emissions from Wabash River Units 2, 3, and 5 for the period May 22, 2008 through the shutdown of the units on September 30, 2009.

Mr. Roebel testified that on March 18, 2010, the Court issued an order approving a Consent Decree entered into by the parties with regard to Gallagher Station. In addition to a contribution of $6.25 million for environmental mitigation projects and $1.75 million in civil penalties, Mr. Roebel testified that the Company has agreed to retire or repower Gallagher Units 1 and 3 with natural gas. A final decision as to whether to retire or convert these units must be made by January 1, 2012. Until that time, Petitioner can continue to operate the units. He stated that if the Company decides to repower these units, the conversion must occur by December 31, 2012. If the Company elects to retire these units, they must be retired by February 1, 2012. He testified that beginning January 30, 2011, and continuing until these units are repowered or retired, the Company has agreed to operate Gallagher 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 lb/mmBTU. The Company has also agreed to surrender SO_2 allowances during the conversion period. Mr. Roebel explained that the Company intends to address the conversion or retirement of Gallagher Units 1 and 3, and other matters in the Consent Decree in separate proceedings filed with the Commission. Mr. Roebel testified that Duke Energy Indiana also agreed in the Consent Decree 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 lb/mmBTU on these units.

Mr. Roebel explained that during 1998 and 1999, Duke Energy Indiana obtained low-cost used pulverizers and installed them at all four of the Gallagher Units. The government only included the pulverizer projects at Gallagher Units 1 and 3 in the NSR lawsuit, even though the Company installed the exact same pulverizers on Units 2 and 4. He stated that since the jury found liability for the pulverizer projects at Units 1 and 3, Petitioner believed it was likely that the government would next file claims on the Units 2 and 4 pulverizer upgrades. He explained that in order to resolve the possibility of further litigation over these issues and to mitigate the risk of a shutdown of Units 2 and 4, the Company thought it prudent, after conducting an economic analysis, to agree to include a DSI System on Units 2 and 4 in return for a commitment from DOJ not to file claims on those units.

Mr. Roebel testified that the Company considered alternatives to installing a DSI System on Gallagher Units 2 and 4, including installing flue gas desulfurization ("FGD") equipment, or retiring those units and replacing the capacity with purchases or a combustion turbine. He stated that with the baghouses already in place at Gallagher, the incremental cost of the DSI System is significantly less than other options. He also testified that the proposed DSI System will help Duke Energy Indiana meet new environmental standards anticipated from EPA in the near term.

Mr. Roebel estimated the cost to install the DSI System on Gallagher Units 2 and 4 to be approximately $16.6 million, which includes the cost of the equipment (based on bids from two vendors), engineering costs, installation costs, contingency, and the cost of the additional continuous emission monitors ("CEM") the Company will have to install under the Consent Decree. He stated that in mid-March, Petitioner began chemical testing of dry sorbent injection on Gallagher Unit 2 using a portable system in order to finalize the engineering design. He testified that the testing process would continue through April, during which time Petitioner would evaluate different SO_2 fuels and test two different absorbent materials, trona and sodium bicarbonate, to determine which has the best SO_2 removal curves. He explained that although trona is a less expensive product, it requires significantly higher injection rates, so the Company is trying to find the most cost-effective combination for the final DSI System design. He stated that the testing will also use several different sizes of trona in an effort to determine removal rates as a function of the material fineness. Petitioner expected the tests to provide information to finalize design parameters such as injection rates, number of injection lances, storage silo size, and location of facilities. Mr. Roebel testified that he believes the cost estimate is reasonable.

Mr. Roebel testified that although the testing will provide much better information for projecting the operating costs of the DSI System, Petitioner has estimated the variable operating costs of the DSI System to be between approximately $2.50/MWhr and $4.50/MWhr in 2010 dollars. He testified that the operating costs will depend heavily on the fuel that is utilized; the percent removal needed to maintain compliance with the limits in the Consent Decree; the reagent used; the efficiency of the utilization of that reagent; and the process needed to fixate and dispose of the final ash product.

Mr. Roebel testified that for planning purposes, the Company expects to be able to remove 50% of the SO_2 with the DSI System. He stated that this would allow Duke Energy Indiana to use coal with an average sulfur content of about 1.6 lbs/mmBTU given the requirements of the Consent Decree. If higher removal rates are achieved, he stated that higher sulfur content coal could be used.

Mr. Roebel testified that the proposed DSI System meets the definition of "clean coal technology" defined by Ind. Code § 8-1-8.7-1. To support this statement, he explained that dry sorbent injection was not in common use at electric generating stations in the United States in 1989. Public Service Company of Colorado was one of the first U.S. utilities to demonstrate the use of dry sorbents for the reduction of SO_2 emissions by participating with the U.S. Department of Energy ("DOE") in a project in Denver Colorado in the early 1990s. Mr. Roebel stated that since that project, the process has been used at approximately 20 electric generating units in the United States - all older, smaller units, similar to Gallagher.

He also stated that the proposed DSI System will be more economically efficient for Gallagher Station than conventional SO_2 reduction technology. In 1989, conventional technology for reducing SO_2 emissions was FGD or scrubbers. At that time, scrubbers could remove approximately 90% of the SO_2 emissions from a coal-fired unit. However, he stated that scrubbers have a very high capital cost and generally are not, and in 1989 were not, cost-effective on small, older units such as Gallagher. According to data found on EPA's website, in 1990 there were only about 10 FGDs on units the size of the Gallagher units in the entire country, about 2.5% of all FGD capacity. Mr. Roebel testified that by contrast, dry sorbent injection has been shown to reduce SO_2 emissions by as much as 70% in certain situations, with significantly lower capital costs. He stated that for planning purposes, Petitioner anticipates reductions of approximately 50% at a much lower cost than with scrubbers. Mr. Roebel sponsored Petitioner's Exhibit A-1, which estimated the annual revenue requirements for Gallagher Units 2 and 4 with the DSI System using lower sulfur coal will be about $22 million less than the annual revenue requirements for those two units with scrubbers. He also stated that while NO_x is not the primary focus of the DSI System, other projects have reported a reduction of NO_x emissions with a DSI System by as much as 10% to 15%. Mr. Roebel believes the likelihood of success of the proposed DSI System to be very high.

Mr. Roebel testified that this clean coal technology will extend the useful life of the Gallagher Units. He stated that the settlement reached with DOJ means that the Company is able to continue to operate the Gallagher Units 2 and 4 on coal instead of a potential shutdown. The DSI System will also assist Duke Energy Indiana in meeting future environmental emission requirements for SO_2. He stated that given the integrated resource planning ("IRP") analyses continue to select a cost effective plan for the Company that includes Gallagher Units 2 and 4 with a DSI System and low sulfur coal instead of retirement, there is value to Duke Energy Indiana's customers in continuing to operate the units with the DSI System and low sulfur coal. He stated that the estimated cost to demolish the Gallagher Station upon retirement is $29,906,000 in 2008 dollars, according to the most recent Sargent & Lundy demolition study. Mr. Roebel testified that, in his opinion, the construction, implementation and use of the proposed DSI System is in the public's interest.

Mr. David E. Freeman, Midwest Integrated Resource Planning Director, described Duke Energy Indiana's IRP process which involves taking a myriad of resource options, and through screening and analysis, methodically funneling them down until reaching an optimal combination of feasible and economic alternatives that will reliably meet the anticipated future customer loads. He stated that Duke Energy Indiana's most recent IRP is its 2009 IRP, filed with the Commission on January 7, 2010. He explained that the Company uses an engineering planning and screening model to screen environmental compliance technology options that are most economic for further consideration in the System Optimizer model. He stated that during the resource integration process, the System Optimizer model uses a linear programming optimization procedure to select the most economic expansion plan, based on Present Value Revenue Requirements, which meets the prescribed reliability criteria and environmental constraints. The model calculates the cost and reliability effects of modifying the load with demand-side management programs or adding supply-side resources to the system. He stated that the modeling of emission-related constraints enables the user to integrate environmental compliance strategies with the supply-side and demand-side resource options.

Mr. Freeman testified that for the Company's 2009 IRP, the environmental compliance alternatives for Gallagher Station passed on to System Optimizer included: activated carbon injection, low sulfur coal with activated carbon injection, low sulfur coal with activated carbon injection and DSI, and retirement of the Gallagher Station. He stated that an FGD or scrubber was not included for consideration because it was not found to be an economic emission reduction option for Gallagher by the engineering screening model, so it was not passed to System Optimizer for further consideration. Mr. Freeman testified that the System Optimizer analysis for the 2009 IRP determined the most cost effective plan was to install DSI Systems on all four units at Gallagher in 2012 and 2013, low sulfur fuel in 2013, and activated carbon injection in 2015. He stated that System Optimizer did not find that it was more cost effective to retire the units. Therefore, the portfolio selected for the 2009 IRP includes the aforementioned environmental compliance equipment on the Gallagher Units.

Mr. Freeman testified that the Company's 2009 IRP included a preliminary look at the modeling of the Consent Decree assuming Gallagher Units 1 and 3 are converted to run on natural gas in 2013 and Gallagher Units 2 and 4 are equipped with DSI Systems in 2011. He explained that the 2009 IRP differs from the Consent Decree in that, under the Consent Decree, the proposed DSI System would be installed on Units 2 and 4 in 2011, instead of on all four Gallagher Units in 2012 and 2013. Also, under the Consent Decree, Duke Energy Indiana has committed to either retiring or converting Gallagher Units 1 and 3 to run on natural gas.

Mr. Freeman testified that he updated the 2009 IRP analyses by using System Optimizer to assess the installation of the DSI System in 2011 instead of 2012 and 2013, and updated the model with Petitioner's latest (Fall 2009) load forecast and the current DSI System cost estimate of $16.6 million. He testified that the updated analyses resulted in the selection of a plan that included the installation of the DSI System on Units 2 and 4 and the use of low sulfur coal in 2011 as the most cost effective plan. He stated that retirement of the units was available as an option, but was rejected by System Optimizer in favor of continued operation of the units with the DSI System. Mr. Freeman also testified that his analysis shows that Units 2 and 4, with the proposed DSI System, will have capacity factors ranging from approximately 9% to 35%, and a combined average capacity factor of 16% for the period 2011-2023.

5. **OUCC's Evidence.** Anthony L. Alvarez, a Utility Analyst II with the OUCC, testified regarding the OUCC's review of the requested relief. Mr. Alvarez described the DSI System as a custom-engineered dry bulk sorbent injection system that continuously transfers, processes, meters, and delivers sorbent materials from storage to injection ports on boiler flue gas ducts. He explained that the reagent, typically sodium or calcium-based dry alkaline sorbent, absorbs SO_2, SO_3, Hg, HCl, and hydrogen fluoride in the flue gas and mitigates the emission of these pollutants. The reagent is injected into the flue gas duct work immediately after a coal-fired boiler or after an air pre-heater and ahead of a particulate collector. He stated that dry reaction products and unused sorbent are carried by the gas and removed from the flue gas, along with fly ash in the particulate collector. With a baghouse, substantial additional SO_2 capture occurs as flue gas passes through fly ash and sorbent collected on the filter surface.

Mr. Alvarez testified that the primary advantages of installing a DSI System on Gallagher Units 2 and 4, compared with typical desulfurization systems, are: (1) low installed equipment cost; (2) no water consumption; (3) no waste water treatment; and (4) no reheating of flue gas. He stated that the DSI System is relatively easy to retrofit existing power plants and power consumption is relatively low in comparison.

Mr. Alvarez testified it is unclear as to whether Petitioner will continue to utilize Illinois Basin coal as its primary fuel source at Gallagher Station. He stated that although Gallagher Units 2 and 4 are capable of burning low-sulfur coal and have an existing baghouse, due to the SO_2 reduction efficiency limit of the DSI System, these units may not be able to burn Illinois Basin coal to attain the Consent Decree mandatory 0.8 lbs/mmBTU SO_2 emission limit. The OUCC acknowledged the technical foundation for Mr. Roebel's assumption that, for planning purposes, Petitioner expects the DSI System to remove 50% of the SO_2, allowing for the use of coal with an average sulfur content of about 1.6 lbs/mmBTU.

Mr. Alvarez opined that the proposed DSI System is "clean coal technology" as defined in Ind. Code § 8-1-8.7. He stated the primary purpose of the DSI System is to directly reduce airborne emissions of sulfur based pollutants associated with the combustion of coal on the existing Gallagher Units 2 and 4 facilities whose emissions will be restricted as mandated by the Consent Decree. He also testified that the proposed DSI System technology was not in general commercial use prior to January 1, 1989. Mr. Alvarez testified that the DSI System will work in tandem with the existing baghouses to give the Gallagher Units 2 and 4 pollution control system the potential for substantial SO_2 emission reduction capability and efficiency. He also stated that the DSI System offers a more efficient technology than those in general use in the 1990s.

Mr. Alvarez raised a concern with Petitioner's cost estimate based upon a disparity between the project cost estimate referenced in Petitioner's data responses and the approximate $16.6 million provided in Mr. Roebel's testimony. He stated that due to the disparity, the OUCC cannot make a determination regarding the reasonableness of the cost estimate.

Mr. Alvarez also raised technical concerns with the shared smokestack configuration currently existing at the Gallagher Generating Station in terms of monitoring and reporting. He explained that Gallagher Units 1 and 2 share a smokestack and Units 3 and 4 share a separate smokestack. The Consent Decree has mandated that Units 1 and 3 either be converted to natural gas or shut down, as well as different emission limits for Units 2 and 4 (0.8 lbs/mmBTU) and Units 1 and 3 (1.7 lbs/mmBTU). Mr. Alvarez testified that with the different restrictions set for units sharing the same smokestack, there is a technical concern pertaining to proper monitoring and reporting. The OUCC suggested Petitioner provide proper and adequate documentation describing in detail the process, personnel, equipment, monitoring, and reporting process that has to be in place to prevent an issue with complying with the emission limits set forth in the Consent Decree. Mr. Alvarez requested confirmation from Petitioner that it intends to install CEMS on each separate duct to determine the emissions from each unit.

Subject to Petitioner addressing the concerns of the OUCC, Mr. Alvarez recommended the Commission approve Petitioner's request for a CPCN.

Cynthia M. Armstrong, a Utility Analyst with the OUCC, discussed the Consent Decree and other regulations that explain Petitioner's decision to install a DSI System on Gallagher Units 2 and 4. She stated that replacement rules for the vacated Clean Air Mercury Rule ("CAMR") and the Clean Air Interstate Rule ("CAIR") could justify the need for the DSI System. She also stated that while EPA has not yet determined what technology it believes will qualify as maximum achievable control technology ("MACT") for Hg, fabric filters (or baghouses) have been shown to be very effective. She stated it is likely that when EPA releases its determination of a mercury MACT, the use of activated carbon injection upstream of the baghouse, in conjunction with a baghouse, will qualify as meeting the MACT standard. She stated Gallagher is already utilizing a baghouse for particulate emissions removal and removing additional amounts of SO_3 with the DSI System from the flue gas may improve the activated carbon's effectiveness to capture mercury.

Ms. Armstrong testified that based upon Petitioner's recent IRP, even in the absence of the Consent Decree, it is reasonable for the OUCC to believe that a DSI System is a low-cost compliance option for Duke Energy Indiana to meet the current SO_2 requirements of CAIR. However, she stated that the OUCC does have some concerns regarding the long-term usefulness of the proposed DSI System. The OUCC is concerned that a stringent SO_2 emission standard will negate the utility of the Gallagher DSI System. The OUCC recommended that Petitioner provide to the Commission, prior to receiving approval for a CPCN, information as to how long it presently believes that it will be able to use the Gallagher DSI System on Units 2 and 4.

Ms. Armstrong also recommended that Petitioner: provide detailed project cost information as well as the incremental per ton cost of removing SO_2 via trona injection; provide the results of the preliminary tests it is conducting to both the Commission and the OUCC as it becomes available; and continue to update the Commission and the OUCC regarding the status of the NSR litigation. Finally, Ms. Armstrong recommended, subject to the OUCC's recommendations, the Commission approve Petitioner's request for a CPCN.

6. **<u>Petitioner's Rebuttal Evidence</u>.** Petitioner offered the rebuttal testimony of Mr. Roebel, who responded to the testimony and recommendations of the OUCC. Mr. Roebel testified that the design of the DSI System is now essentially complete. Petitioner has entered into a contract with a vendor for the main equipment and is currently in the process of evaluating formal bids for other portions of the work. He stated that based on this updated information, the estimated cost of the DSI System still appears very reasonable. He testified that included in the $16.6 million cost estimate are costs associated with ash fixation – a process that involves mixing the DSI byproduct removed from the baghouses with another material, such as lime, to stabilize it before it can be disposed of in the landfill. He stated the costs include approximately $5 million for the cost of the equipment and a reasonable figure for possibly needed fixation materials. He stated tests are ongoing to determine whether ash fixation is necessary for Gallagher Units 2 and 4. The cost estimate also includes a pug mill (*i.e.,* a type of industrial mixer), a mixing tank and storage silo that would be used for fixation purposes, as well as costs associated with purchasing the mixing agent and electrical and mechanical piping and wiring. He testified Petitioner anticipates receiving final results from testing in early August, and will then ascertain whether it needs to expend the additional capital for fixation. He stated it is possible that the proposed DSI System will be constructed below the $16 million estimate, if Petitioner does not end up needing to include ash fixation.

Mr. Roebel testified that in response to the OUCC's data request, the Company provided its actual engineering cost estimate, which did not include costs associated with ash fixation, an amount for contingency, AFUDC and other loadings and overheads. He stated that this detailed cost estimate is accurate and formed the basis of the $16.6 million figure, but likely caused unnecessary confusion and resulted in the disparity between the figures referenced in Mr. Alvarez' testimony. Mr. Roebel testified Petitioner would be willing to provide an additional update on its cost estimate at the time of the evidentiary hearing if the Commission and OUCC so desire. He also testified that there is no reason to believe that Petitioner would exceed its $16.6 million estimate.

Mr. Roebel provided an update on the testing performed on the DSI System. He testified that Phase I of the testing is complete. As a result of the testing, milled trona was selected as the preferred initial reagent and the economizer outlet is the recommended injection location in the DSI System design. He also testified that initial results demonstrate that the proposed DSI System will help Petitioner meet the terms of the Consent Decree as the dry sorbent injection effectively reduces the SO_2 emissions to satisfactory levels for all coals evaluated. Mr. Roebel testified that Duke Energy Indiana plans two additional phases of testing before final design of the DSI System is completed. Phase II will evaluate the effectiveness of hydrated lime injection into the furnace. The test injection would be for a short period of time, followed by a furnace inspection. He explained that if results look promising, a longer test injection will be scheduled for late summer/early fall. He testified that Phase III of the testing will include analysis of the various ash and coal samples collected during the prior testing to assess the need for ash fixation. He stated that these results are expected by early August 2010.

Mr. Roebel responded to the OUCC's concerns regarding the long-term usefulness of the proposed DSI System for Gallagher Units 2 and 4. He stated that Duke Energy Indiana constantly monitors and evaluates the potential environmental compliance standards being considered by the government. The Company builds into its IRP and other internal models the potential range of environmental requirements to determine the type and cost-effectiveness of the various compliance options available. He stated that although it is possible EPA will make changes to CAIR, or Congress could enact some additional unforeseen requirements, that would force the shutdown of Gallagher Units 2 and 4, at this time, these units are estimated to run for the next 10-15 years under current and reasonably anticipated environmental regulations, all of which are factored into Petitioner's IRP analysis.

Mr. Roebel responded to the OUCC's concerns regarding the shared smokestack configuration in terms of monitoring and reporting emission limits. He explained that pursuant to the Consent Decree, Duke Energy Indiana will install CEMs in the outlet ductwork of the baghouses at each of the Gallagher units, in addition to the CEMs already installed on each shared smokestack. He stated that although the Gallagher units share two smokestacks, the CEMs will allow monitoring of each individual unit's SO_2 production rate. He also stated that Duke Energy Indiana has agreed to extensive monitoring requirements as part of the Consent Decree.

Mr. Roebel testified that although the incremental per ton cost of removing SO_2 via trona injection will vary depending on reagent costs and other factors, Petitioner estimated the range to be between approximately $982 and $1,226/ton of SO_2 removal. He stated that the range will be lower if Petitioner does not have to install ash fixation. He explained that by comparison, Petitioner estimated that the incremental per ton cost of removing SO_2 with an FGD at Gallagher would be between $1,766 and $3,442/ton of SO_2 removed. Mr. Roebel concluded with his opinion that the construction, implementation and use of the proposed DSI System is in the public interest.

7. **Commission Discussion and Findings.**

A. Ind. Code §§ 8-1-8.7-1 and 8-1-8.7-3 Review and Findings. Ind. Code § 8-1-8.7-3 requires that before a utility may use clean coal technology at its generating plants, it must obtain from the Commission a certificate stating that the public convenience and necessity will be served by the use of such clean coal technology, the latter being defined in Ind. Code § 8-1-8.7-1 as technology that reduces airborne emissions of sulfur or nitrogen based pollutants associated with the combustion or use of coal that either: (a) was not in general use at the same or greater scale in new or existing facilities in the United States as of January 1, 1989; or (b) has been selected by DOE under its Innovative Clean Coal Technology program and was finally approved for such funding on or after January 1, 1989.

Mr. Roebel testified that the proposed DSI System on Gallagher Units 2 and 4 is required for Petitioner to comply with the Consent Decree issued in the NSR lawsuit. The Consent Decree requires Petitioner 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 lb/mmBTU on these units. Mr. Roebel testified that with the proposed DSI System, Petitioner anticipates a reduction of SO_2 emissions of approximately 50% and a potential reduction of NO_x by as much as 10-15%. Mr. Roebel testified that dry sorbent injection, using either trona or sodium bicarbonate, was not in common use at electric generating stations in the United States in 1989. He also testified that in the early 1990s, a Colorado utility participated in a DOE-funded project to demonstrate the use of dry sorbents for the reduction of SO_2 emissions. Accordingly, based on the testimony presented in this Cause, we find that the proposed DSI System constitutes clean coal technology, as defined in Ind. Code § 8-1-8.7-1.

1. The Costs of the Clean Coal Technology Compared to Conventional Emission Reduction Facilities. The evidence shows that Petitioner evaluated alternatives to the selected technology, including FGD or scrubbers. Mr. Roebel testified that scrubbers have a high capital cost and generally are not cost-effective on small, older units such as Gallagher. Petitioner's Exhibit A-1 details the estimated annual revenue requirements for Gallagher Units 2 and 4 with the DSI System using lower sulfur coal will be about $22 million less than the annual revenue requirements for those two units with scrubbers.

Based on the evidence presented in this matter we find that the proposed SO_2 emissions reductions could not be achieved as cost-effectively through conventional technologies. Further, we find that Petitioner has adequately considered the available options and the DSI System is a reasonable means to achieve reduced emissions in compliance with the Consent Decree. We also find that Duke Energy Indiana's construction cost estimate of $16.6 million is reasonable and should be approved.

2. Whether the Proposed DSI System Will Extend the Useful Life of Existing Generating Facilities and Costs of Retirement of Existing Units. Mr. Roebel testified that absent the Consent Decree, Duke Energy Indiana could be facing additional claims of NSR violations on Gallagher Units 2 and 4, with the possibility of a shutdown order such as seen at Wabash River. The DSI System will allow Petitioner to continue to operate Gallagher Units 2 and 4 on coal for the next 10-15 years, under current and reasonably anticipated environmental regulations. Mr. Freeman testified both the Company's 2009 IRP and the updated analyses for this proceeding rejected retirement of the units in favor of continued operation of the units with the DSI System. Mr. Roebel provided an estimated cost to demolish the Gallagher Station upon retirement of approximately $29,906,000 in 2008 dollars. In addition, in response to the Commission's Docket Entry, Petitioner stated that, from its initial read, it believes the adoption of EPA's proposed Clean Air Transport Rule, or the alternatives included therein, is not likely to affect the effectiveness and long-term usefulness of the proposed DSI System or the remaining useful life of Gallagher Units 2 and 4. Accordingly, we find the Petitioner's proposal extends the useful life and the value of these facilities.

3. Potential Reduction of Sulfur and Nitrogen to be Achieved by the Proposed DSI System. Mr. Roebel explained that the Company anticipates being able to remove as much as 50% of the SO_2 with the DSI System. He also testified that while NO_x is not the primary focus of the DSI System, other projects have reported that NO_x emissions have been reduced with a DSI System by as much as 10-15%. Accordingly, we find that the Petitioner's proposal provides a significant reduction in SO_2, as well as a potential reduction of NO_x.

4. Federal and State Pollutant Emission Standards and Likelihood of Success. The DSI System will enable Petitioner to meet the requirements of the Consent Decree.

In addition, Mr. Roebel testified that the reductions in SO_2, NO_x, and Hg at Gallagher as a result of the DSI System will ultimately help Duke Energy Indiana meet existing standards, as well as anticipated revised CAIR and CAMR obligations. He further testified that he believes the likelihood of success of the DSI System to be very high. In response to the Commission's Docket Entry, Petitioner stated that it believes the proposed DSI System will also be sufficient to satisfy the requirements of the proposed Clean Air Transport Rule (and its proposed alternatives), in combination with the other Consent Decree actions. Based upon the testimony, we find that there is a likelihood of success in the implementation and utilization of the DSI System on Gallagher Units 2 and 4.

5. Dispatching Priority. Mr. Freeman testified that Gallagher Units 2 and 4, with the proposed DSI System, will have capacity factors ranging from approximately 9% to 35%, and a combined average capacity factor of 16% for the period 2011-2023. The Commission finds that Duke Energy Indiana's determination regarding the dispatching priority appears to be reasonable, appropriate, and in compliance with Indiana law.

B. Ind. Code § 8-1-8.7-4 Review and Findings. Ind. Code § 8-1-8.7-4 requires that as a condition for receiving the certificate required under Ind. Code § 8-1-8.7-3 of this chapter, an applicant must file an estimate of the cost of constructing, implementing, and using clean coal technology and supportive technical information. Based on the information provided, and following public hearing, the Commission must determine whether the public convenience and necessity will be served by the construction, implementation, and use of clean coal technology; if the estimated cost should be approved; and, determine whether the facility utilizes and will continue to utilize Indiana coal as its primary fuel source or is justified, because of economic considerations or governmental requirements, in utilizing non-Indiana coal after the technology is in place.[3]

Pursuant to the requirements set forth in Ind. Code § 8-1-8.7-4, and based on our review of the evidence presented in this Cause, the Commission hereby finds as follows:

1. Public Convenience and Necessity Review Regarding the Construction, Implementation and Use of Clean Coal Technology. Petitioner has adequately demonstrated the need for the DSI System on Gallagher Units 2 and 4. Mr. Freeman testified that the Company's 2009 IRP and the updated analyses for this proceeding both rejected retirement of the units in favor of continued operation of the units with the DSI System. The DSI System will assist the Company in complying with possible future environmental requirements related to SO_2 emissions and will allow these units to continue to operate for the benefit of Petitioner's customers under the Consent Decree.

[3] We recognize that in *General Motors Corp. v. Indianapolis Power & Light Co.*, 654 N.E.2d 752 (Ind. Ct. App. 1995), the Court of Appeals ("Court") declared that a portion of Ind. Code § 8-1-2-6.6 relating to Indiana coal violates the Commerce Clause of the United States Constitution. The Court severed the unconstitutional provision from the remainder of the statute, which was held to be valid and effective. The Court stated that if a plan "is found by the Commission to be the option best fitting the non-protectionist criteria in the statute, no bar exists to its approval on the basis that it includes the use of Indiana coal...." *Id.* at 767. Thus, the use of Indiana coal will not be used as a prerequisite for Petitioner to receive a clean coal technology certificate for the DSI System.

2. Reasonableness of Estimated Costs. Petitioner's witness Mr. Roebel testified that the current estimated cost of the DSI System is approximately $16.6 million and that Petitioner has no reason to believe that it would exceed this amount. Mr. Roebel also testified that the estimated variable operating costs of the DSI System are between approximately $2.50/MWhr and $4.50/MWhr, depending on the fuel ultimately utilized; the percent removal of the system needed to maintain compliance with the limits in the Consent Decree; the reagent used; the efficiency of the utilization of that reagent; and the process needed to fixate and dispose of the final ash product. Petitioner further submitted into the record as Petitioner's Exhibit D-Confidential, a detailed cost estimate for the proposed DSI System, including the potential costs associated with ash fixation.

Based on our review of the evidence, we find that Petitioner has adequately demonstrated the need for installing and using the DSI System on Gallagher Units 2 and 4. We also find that, based on the foregoing, the public convenience and necessity will be served by the use of the DSI System on Gallagher Units 2 and 4. The estimated costs of these projects are approved, and Petitioner should be granted a Certificate of Public Convenience and Necessity for the use of the DSI System.

Although the Commission is granting a Certificate of Public Convenience and Necessity for the use of the DSI System on Gallagher Units 2 and 4 and approving the estimated costs of these projects, no decision is being made herein with respect to Duke Energy Indiana's recovery of the costs of these projects. As noted above (*supra* at p.2) and stated in our June 30, 2010 Order (at pp. 9-12) in Cause No. 38707 FAC 84, Duke Energy Indiana will be filing a separate proceeding no later than September 30, 2010 for the purpose of addressing issues related to the NSR litigation and its impacts, including cost recovery for the installation of the DSI System. Consequently, Duke Energy Indiana's recovery of any costs associated with the DSI System may be addressed in that subsequent proceeding.

3. Ongoing Review Under Ind. Code § 8-1-8.7-7. In its Petition, Duke Energy Indiana requested ongoing review of the construction of its clean coal technology project. In accordance with Ind. Code § 8-1-8.7-7, Petitioner is to submit, at least annually, unless the utility and Commission agree otherwise, a progress report detailing any revisions in the cost estimates or the planned construction. The Commission must hold a hearing before it may approve or deny a proposed increase in the cost estimate for the implementation, construction, or use of the clean coal technology. If the Commission approves the construction and the costs, that approval forecloses subsequent challenges to the inclusion of those costs in the utility's rate base on the basis of excessive cost, inadequate quality control, or inability to employ the technology. Based on the evidence presented, we hereby find that Petitioner's request for ongoing review of the construction of its clean coal technology project should be granted. Petitioner shall report project progress and updated cost information on or before September 1, 2011.

C. Confidential Information. On June 25, 2010, the Presiding Officers made a preliminary finding that certain designated information marked "Confidential" as requested in Duke Energy Indiana's Motion for Protection of Confidential and Proprietary Information should be treated as confidential in accordance with Ind. Code § 5-14-3-4 and that confidential procedures should be followed with respect to this confidential information. Upon review of the confidential information submitted pursuant to the Presiding Officer's preliminary determination, the Commission confirms the prior preliminary findings that the confidential information contains confidential, proprietary and competitively sensitive trade secret information that has economic value to Duke Energy Indiana; neither being known to or ascertainable by, its competitors and other persons who could obtain economic value from the knowledge and the use of such information; that the public disclosure of such information would have a substantial detrimental effect on Duke Energy Indiana; and that the information is subject to efforts of Duke Energy Indiana that are reasonable to maintain its secrecy. Accordingly, the confidential information contained in the exhibits submitted in this proceeding are exempt from the public access requirements of Ind. Code §§ 5-14-3-3 and 8-1-2-29 and shall continue to be held as confidential by the Commission.

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

1. Duke Energy Indiana's proposed DSI System constitutes "clean coal technology" pursuant to Ind. Code § 8-1-8.7 *et seq.*, and is hereby granted a Certificate of Public Convenience and Necessity for the use of the proposed DSI System.

2. Duke Energy Indiana's cost estimate of $16.6 million is reasonable and hereby approved. Petitioner may seek to recover the costs related to the Gallagher DSI System via rates or a rate recovery mechanism in a subsequent proceeding.

3. Petitioner's request for ongoing review of its clean coal technology projects as described in this Order shall be and hereby is granted. Petitioner shall file in this Cause a project progress report and updated cost information on or before September 1, 2011.

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

HARDY, ATTERHOLT, LANDIS, MAYS AND ZIEGNER CONCUR:

APPROVED: SEP 08 2010

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