THE CLEAN COAL TECHNOLOGY PROGRAM

The DOE commitment to clean coal technology development has progressed through three phases. The first phase was the Clean Coal Technology Demonstration Program (CCTDP), a model of government and industry cooperation that advanced the DOE mission to foster a secure and reliable energy system. With 33 projects completed, the CCTDP has yielded technologies that provide a foundation for meeting future energy demands that utilize the vast U.S. reserves of coal in an environmentally sound manner. Begun in 1985, the CCTDP represents a total investment value of over \$3.25 billion. The DOE share of the total cost is about \$1.30 billion, or approximately 40 percent. The project industrial participants (non-DOE) have provided the remainder, nearly \$2 billion.

Two programs have built on the successes of the CCTDP. The first is the Power Plant Improvement Initiative (PPII), a cost-shared program patterned after the CCTDP and directed toward improved reliability and environmental performance of the nation's coal-burning power plants. Authorized by the U.S. Congress in 2001, the PPII concluded with four successfully completed projects that focused on technologies enabling coal-fired power plants to meet increasingly stringent environmental regulations at the lowest possible cost. The total value of these projects is \$71 million, with DOE contributing \$31 million or 42.7 percent.

The second follow-on program is the Clean Coal Power Initiative (CCPI). Authorized in 2002, the CCPI had a goal of accelerating commercial deployment of advanced technologies to ensure that the nation has clean, reliable, and affordable electricity. The first CCPI solicitation (CCPI-1) was open to "any technology advancement related to coal-based power generation that results in efficiency, environmental, and economic improvement compared to currently available state-of-the-art alternatives." Of five projects awarded, two were discontinued and three were successfully completed. The total cost of the five projects was approximately \$121 million, with the DOE share being \$54 million or 44.8 percent. In February 2004, the second CCPI solicitation (CCPI-2) was issued seeking proposals to demonstrate advances in coal gasification systems, technologies that permit improved management of carbon emissions, and advances that reduce mercury and other power plant emissions. In October 2004, four projects were selected. One project withdrew prior to award, one is complete, and two are ongoing. The three awarded projects are valued at over \$4 billion with a DOE share of \$322 million. On August 11, 2008, DOE issued the Funding Opportunity Announcement for the third solicitation (CCPI-3A). CCPI-3A specifically focused on the capture and sequestration, or beneficial reuse, of CO_2 emissions from coal-based electricity production (minimum 50 percent gross energy output as electricity). Following the passage of ARRA, DOE announced the re-opening of the third solicitation. On June 9, 2009, DOE issued an amendment that provided for a second application due date (CCPI-3B) of August 24, 2009. A total of \$1.4 billion was made available for awards under CCPI-3A and -3B. Of the total amount, approximately \$800 million was provided under ARRA with the remainder provided through the annual congressional appropriations process. Of the four projects awarded, one withdrew and three are ongoing. The three ongoing projects are valued at over \$6 billion with a DOE share of approximately \$1 billion.

nation's power grid. PPII was followed by the Clean Coal Power Initiative (CCPI) in 2002. CCPI ensures the ongoing development of advanced systems for commercial power production emerging from DOE's core fossil-fuel research programs.

CCPI Program

As coal is likely to remain one of the nation's—and world's—lowest-cost electric power resources for the foreseeable future, a new commitment to further reduce the environmental challenges of its continued use through even more advanced clean coal technologies is required. CCPI is an innovative technology demonstration program initiated to foster more efficient, advanced, clean coal technologies in the 21st century for use in new and existing electric power generating facilities in the U.S. CCPI solicitations began in 2002. As of this report, three solicitations have been issued (CCPI-1, CCPI-2, and CCPI-3). After the submission of proposals for the initial CCPI-3 solicitation (CCPI-3A), the solicitation was re-opened with minor amendments for a second round of proposals (CCPI-3B). Projects selected under CCPI-3A and -3B could be funded, in whole or in part, from funds appropriated under the American Recovery and Reinvestment Act of 2009 (ARRA).

CCPI builds on the successes of the original CCTDP and encompasses a broad spectrum of research and large-scale projects that target today's most pressing environmental challenges. CCPI is an industry/government cost-shared partnership that accelerates commercial deployment of advanced technologies to ensure a reliable and affordable supply of electricity while simultaneously protecting the environment. CCPI is planned and managed by DOE's Office of Fossil Energy (FE) and implemented by the National Energy Technology Laboratory (NETL).

The CCPI mission is to enable and accelerate deployment of advanced technologies to ensure that the United States has clean, reliable, and affordable electricity. This mission is executed through the CCPI program goals of reinvigorating private sector development of new coal-based power technologies that can meet increasingly stringent environmental regulations, and establishing the technological foundation for "zero" emission coal-based energy facilities within the nation's power industry.

REGULATORY HISTORY

Title III of the 1990 Clean Air Act Amendments (CAAA) identified 189 substances emitted by fossil fuel combustion that may be toxic or hazardous. These 189 substances are usually referred to as hazardous air pollutants (HAPs) or air toxics. The CAAA required the Environmental Protection Agency (EPA) to evaluate these pollutants by source as well as their potential harm to human health and the environment. The EPA was also required to determine the need to control the emission of HAPs. DOE's NETL, in collaboration with the Electric Power Research Institute (EPRI), comprehensively addressed the CAAA requirements specific to the electric power industry with a series of projects from 1990 to 1997. In the course of these projects, it was found that non-mercury toxic metals were captured by existing particulate removal equipment and that they were emitted at or near their detection limit. These projects provided the majority of the data for two Congressionally-mandated EPA Reports to Congress. The first report, the "Mercury Study Report to Congress," was issued in 1997 and found that coal-fired power plants were the largest U.S. source of anthropogenic mercury emissions. The second report, the "Study of Hazardous Air Pollutant Emissions from Electric Utility Steam Generating Units–Final Report to Congress" was issued in 1998. This second report concluded that mercury from coal-fired power plants was the HAP of "greatest potential concern." This conclusion lead to the initial emphasis on regulating mercury and the development of mercury capture technologies and that additional research and monitoring was warranted for the other HAPs.

In 1999 and 2000, the EPA, in cooperation with DOE, issued an Information Collection Request (ICR). The purpose of the ICR was two-fold. One aim was to refine the mercury emission inventory from coal-fired power plants. The other was to determine the mercury control capabilities of existing and new, potentially viable technologies. In the same timeframe, the National Academy of Sciences (NAS) conducted an evaluation of the health impacts of mercury. Based on the ICR and the NAS evaluation, the EPA determined that there was a "plausible link" between emissions of mercury from coal-fired power plants and the bioaccumulation of mercury in fish, as well as animals that eat fish. Since consumption of fish is the primary pathway for human exposure to mercury, the EPA determined that it was necessary to reduce mercury emissions from fossil fuel combustion in power plants. The EPA issued its decision to regulate mercury in December of 2000.

The EPA issued the Clean Air Mercury Rule (CAMR) on March 15, 2005. This was the first regulation to specifically address mercury emissions from coal-fired power plants. The CAMR complemented the Clean Air Interstate Rule (CAIR), which was issued to reduce the emissions of NO_X and SO_2, since technologies designed to remove other pollutants often coincidentally remove some mercury. The net effect of these two rules was expected to be a 70 percent reduction in mercury emissions, which are currently estimated at 48 tons per year. The CAMR intended to create a market-based cap-and-trade program to reduce mercury emissions. The reduction would have taken place in two phases. Mercury emissions were to be capped at 38 tons per year in 2010. This level of emissions would have been achieved by coincidental mercury capture in technologies whose primary purpose is the control of other pollutants. By 2018, total mercury emissions from all coal-fired power plants were to be limited to 15 tons per year. In addition, new coal-fired units would have to meet New Source Performance Standards.

The CAMR was applicable to all coal-fired utility boilers with a heat input of 73 MW (thermal) or 250 million Btu per hour. Industrial cogeneration boilers would have been regulated if they sell over 25 MW of electrical power and more than one third of their maximum output to a power distribution system. In 2008, the D.C. Circuit Court vacated the CAMR and remanded the CAIR. The EPA Administrator signed a new rule on December 16, 2011, and it was published in the Federal Register on February 16, 2012. This rule, Mercury and Air Toxics Standards (MATS), regulates mercury, HCl, and a number of non-mercury air toxic metals emitted from power plants. These are antimony (Sb), arsenic (As), beryllium (Be), cadmium (Cd), chromium (Cr), cobalt (Co), lead (Pb), manganese (Mn), nickel (Ni), and selenium (Se). MATS include separate standards for existing plants and new or refurbished generating units. Each unit is also regulated differently depending on whether it burns low rank or non-low rank coal. All power plants have three years to comply and the deadline can be extended one year by state agencies—an option expected to be broadly available.

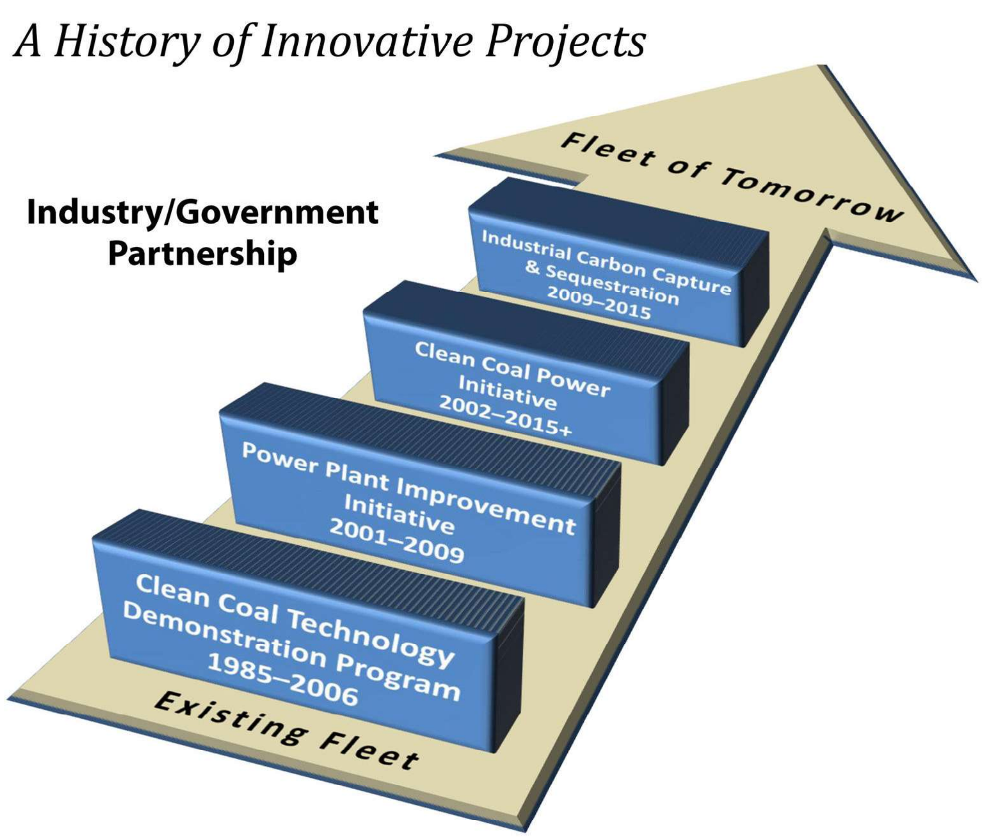
MATS establishes alternative quantitative emission standards, including SO_2 (as a surrogate for HCl). Filterable particulate matter serves as a surrogate for non-mercury air toxic metals, which can also meet a standard based on the total emissions of the eight non-mercury air toxic metals or the plant may meet a separate standard for each of these metals. The standards set work practices instead of numerical limits to limit emissions of organic air toxics, including dioxin/furan, from existing and new coal- and oil-fired power plants. In MATS the emission standards for new or refurbished plants are expressed as pounds per megawatt hours or pounds per gigawatt hours. Existing plants can meet standards based on either electric power output or the heat content of the coal fed to the boiler.

According to "Clean Coal Technology Programs: Program update 2006", CCPI Round 1 (CCPI-1) criteria for candidate projects was very broad in that the solicitation was open to "any technology advancement related to coal-based power generation that results in efficiency, environmental and economic improvement compared to currently available state-of-the-art alternatives." The broad approach taken by CCPI-1 was intended to benefit from the full range of technological advancements made since the last major clean coal technology solicitation had been issued in 1992. Of the eight projects initially selected under CCPI-1, five awards were made. Two of the awarded projects ended prior to successful completion. The remaining three projects are complete and are the subject of this report.

CCPI-2 encouraged proposals that demonstrate advances in coal gasification systems, technologies that permit improved management of carbon emissions, and advancements that reduce Hg and other power plant emissions. The choice of the CCPI-2 solicitation categories reflected DOE's judgment of the most pressing technological needs confronting the nation's power industry in the 2010 to 2020 time frame.

CCPI Round 3 (CCPI-3) required projects that could demonstrate the capture and sequestration or the beneficial use of carbon dioxide (CO_2) from coal-fired power plants. The technologies to be demonstrated could consist of new, integrated facilities or retrofits of existing plants. After an initial round of projects was awarded, a second round of projects was awarded under CCPI-3 in December 2009 with funds made available under ARRA.

The CCPI is closely linked with R&D activities paving the way for ultra-clean, fossil-fuel based energy complexes in the 21st century. The Clean Coal Technology Roadmap was developed in January 2004 with the cooperation of the coal and power industry to address short- and long-term coal technology needs, which support the clean coal initiatives. Projects selected under the CCPI advance efficiency, environmental performance, and cost competitiveness well beyond that of technologies that are currently in commercial service, which is consistent with the Energy Policy Act of 2005.



DOE's Coal Demonstration Programs

Demonstration of Integrated Optimization Software at the Baldwin Energy Complex

Introduction

A coal-fired power plant is a complex grouping of dynamic and interrelated systems. An effort to optimize one aspect of the operation of a system has the potential, in some cases, to adversely affect other operational aspects of the same or different systems. An example would be that reducing the heat rate of a power plant through an increase in combustion efficiency might also result in an increase in the rate of NO_x formation due to possible higher combustion temperatures. Therefore, overall plant optimization must include the ability to monitor individual systems and ensure their operation is not adversely impacted by changes in the same or related systems.

NeuCo, Inc. (NeuCo) of Boston, Massachusetts, demonstrated overall plant performance optimization by utilizing sophisticated computational techniques to increase power plant efficiency and reduce air emissions at the Dynegy Midwest Generation Baldwin Energy Complex (BEC). The BEC consists of three 600 megawatt electric (MWe) coal-fired units located in Randolph County, Illinois, which are designed to fire high-sulfur bituminous coal. All three units switched to Powder River Basin (PRB) coal in 2002 to reduce SO_2 emissions.

The Cooperative Agreement was awarded on February 18, 2004, and the project was completed on November 17, 2007. The project cost was $19,094,733 with a DOE share of $8,592,630 (45 percent).

Project Objectives

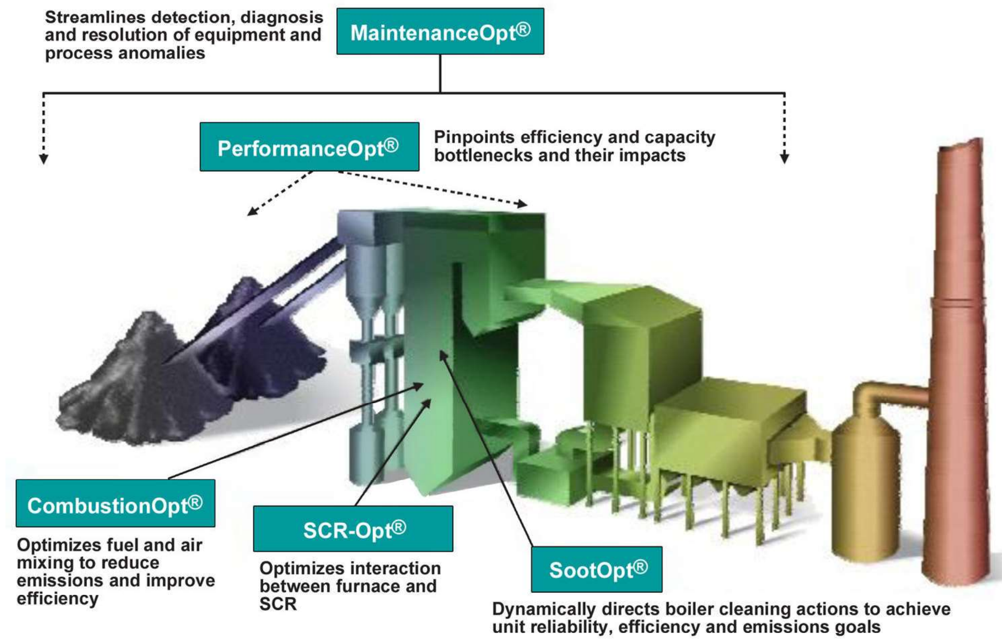
Project objectives were to reduce the BEC NO_x emissions by five percent, increase efficiency by 1.5 percent, and increase net annual electrical power production by 1.5 percent by improving reliability and availability. Additional objectives were to reduce greenhouse gases, Hg, and particulates, and to increase profitability through lower costs, improved reliability, and greater commercial availability. The overarching objective for the application of integrated optimization software to coal-fired power plant operations was to improve coal-based generation's emission profile, efficiency, maintenance requirements, and plant asset life such that the abundant coal resources of the United States remain viable well into the foreseeable future.

The need for integrated optimization software arose, in part, due to the dynamic complexity of the systems present in both modern and retrofitted coal-fired power plants. The optimization process differs significantly from that of normal power plant system operation. Typically, operators make occasional adjustments to the various controls to maintain a process output within an acceptable range based on their understanding of how the adjustment will affect unit performance. While this method keeps operating parameters within an acceptable range, it does not optimize unit operation. However, a control system with optimization capability can explore the relationships between the variables in a system and manage performance more dynamically. An integrated optimization system adds another level of control at the combined system level to optimize not only each system, but the overall performance of all managed systems as well. With the objective of integrated optimization in mind, five separate but integrated optimization modules were developed that addressed the following plant systems: combustion, sootblowing, selective catalytic reduction (SCR) operations, overall unit thermal performance, and plant-wide availability optimization.

Project Description

The NeuCo project at BEC consisted of the design, installation, and demonstration of five integrated AI-based optimization modules for coal-fired power plant operations. Performance optimization modules were developed and implemented for three plant systems: combustion, sootblowing, and SCR operations. In addition, supervisory modules were demonstrated for overall unit thermal performance and plant-wide maintenance optimization. The five individual optimization modules were linked together and coordinated by NeuCo's proprietary ProcessLink® technology.

These optimization modules, although separate, communicated through NeuCo's ProcessLink technology. The modules on Units 1, 2, and 3 did not use theoretical or empirical relationships to model respective unit operations, but rather the technology "learned" these relationships from actual unit operations. The learning capability of the technology was based on the use of neural networks (NNs), first principles, expert systems,



Overview of the Optimizers at BEC

direct search optimization, and fuzzy logic (FL) in addition to enterprise software and a robust calculation engine to link the individual optimization modules and achieve the optimum overall result.

The demonstration technology operated in two modes: closed loop and an advisory mode. The closed loop mode permitted the optimization modules to directly control the plant in real-time. The advisory mode provided guidance to the operator, who then decided whether or not to implement the technology.

CombustionOpt and SCR-Opt

CombustionOpt and SCR-Opt were tightly integrated and are described together. CombustionOpt and SCR-Opt used neural network technology to learn relationships among system variables without the need for prior understanding of what those relationships might be. Once the relationships were learned, CombustionOpt used this Information to change input variables to achieve the performance objectives determined by the plant operators. The learning process was ongoing and based on real-time and recent data so as to constantly update the relationship between system input variables and the desired performance objectives. Important system variable relationships for the CombustionOpt module included plant heat rate, the rate of NO_x formation in the furnace, and ammonia (NH_3) consumption for the SCR system installed on Units 1 and 2.

CombustionOpt calculated the control settings that improved the mixing of the fuel and air in the furnace in real-time for literally dozens of different dampers and actuators, leading to reduced furnace NO_x production while maintaining combustion efficiency. Additionally, the calculations were repeated every minute resulting in more numerous, but smaller changes based on current boiler conditions. Not only were process outputs kept within an acceptable range of operation, they were optimized within that range to meet performance objectives established by plant operators.

If a unit is equipped with an SCR, CombustionOpt and SCR-Opt are integrated to mix the fuel and air in the furnace to reduce furnace NO_x production and maintain critical combustion parameters such as combustion efficiency, while increasing SCR efficiency. The integrated goals of these models are to maintain Cyclone Main Flame Scanner Quality and reduce SCR inlet NO_x, which results in lower NH_3 flow to the SCR system. Therefore, by using an integrated control approach, both furnace and SCR performance are optimized.

SootOpt

A sootblowing operation utilizes steam (or other media) for cleaning the boiler tubes. It does so at the expense of unit efficiency because energy is required to generate the cleaning media. Sootblowing also results in wear on the boiler parts being cleaned. However, slagging and fouling can also result in lower furnace efficiency, increased NO_x production, and excessive flue gas exit temperatures. SootOpt optimized cleaning action effectiveness and achieved improved boiler performance by minimizing the energy expended to generate cleaning media.

SootOpt combined sophisticated optimization methods in conjunction with a control system to optimize the power plant boiler soot blowing operation. SootOpt replaced the traditional schedule-based and operator-controlled soot blowing philosophy, which was basically a disadvantageous hit-or-miss approach.

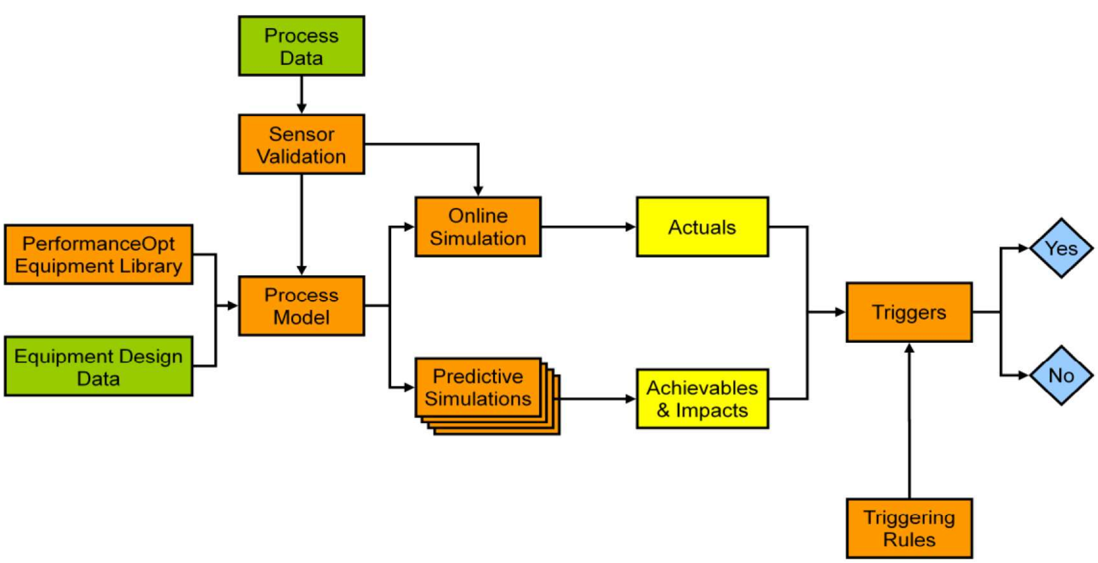
PerformanceOpt

PerformanceOpt provided a predictive performance management capability that identified efficiency and capacity losses so that operators could lower operating costs by remedying their cause. PerformanceOpt identified problems that were causing plant performance limitations by comparing actual plant performance to predicted performance. The predictive component of PerformanceOpt performed mass and energy balances on a minute-by-minute basis and computed the results for thousands of variables by utilizing a detailed first-principles model of the unit with scenario generation capability to quantify what was achievable under current operating conditions. PerformanceOpt continuously monitored key equipment and unit-level performance factors and detected, in real-time, when actual performance deviated from what had been predicted. For each problem identified, PerformanceOpt calculated the efficiency and capacity benefit that could be realized by resolving that problem. PerformanceOpt also ensured model accuracy and reliability through sensor validation mechanisms and equipment out-of-service logic.

MaintenanceOpt

MaintenanceOpt continuously monitored process and equipment data to identify anomalies that might indicate reliability, capacity, or efficiency problems. In addition to potential problem detection, MaintenanceOpt added value by suggesting the most likely causes of problems and estimating the impacts on efficiency, reliability, and capacity. These estimates formed a basis for MaintenanceOpt to prioritize the order in which to address the problems.

MaintenanceOpt provided plant engineers with a suite of diagnostic tools that assisted them with the process of problem correction and increased its effectiveness. Among the knowledge tools available were diagnostics, recommended actions, and the identification of potential



PerformanceOpt Components in Problem Identification

impacts and risks. MaintenanceOpt demonstrated the capability to detect both slowly developing problems as well as those that could have a critical near-term reliability impact. Sufficient information was available within MaintenanceOpt to assist plant engineers in determining the legitimacy of the problem—whether it is real or the result of a sensor malfunction. And finally, MaintenanceOpt supported the diagnosis and resolution of problems found by other optimizers such as PerformanceOpt, CombustionOpt, and SootOpt.

Results

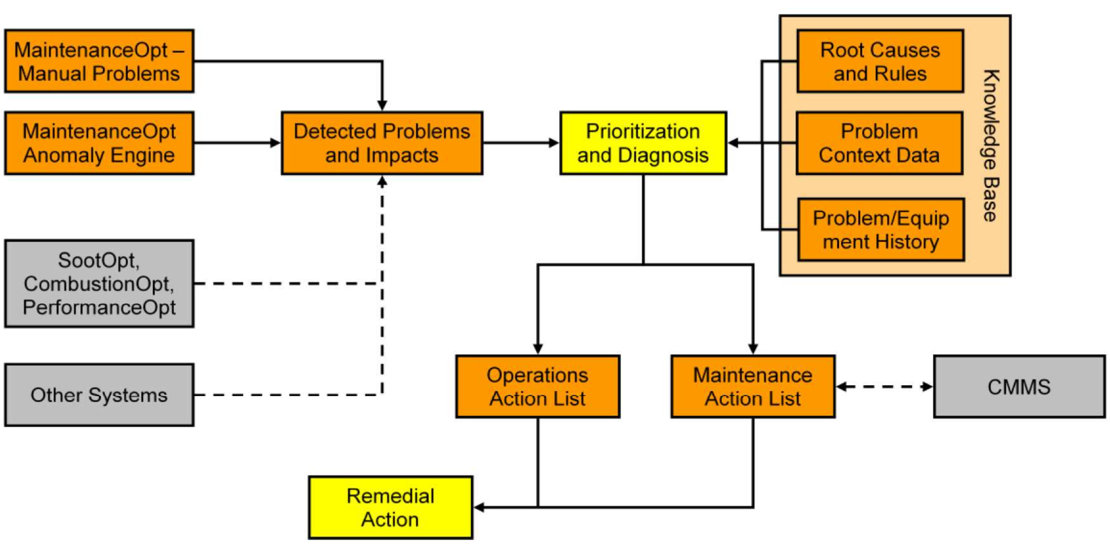
The optimizer modules were developed and refined during the project period. The optimization modules, in concert with NeuCo's proprietary ProcessLink® technology, directly controlled the plant in closed loop mode or advised plant operators of suggested actions in an advisory mode. The results discussed in this section were obtained with the technology operating in the closed loop mode.

Different combinations of the optimization modules were installed on each of the three BEC units. Unit 1, which is a cyclone-fired unit, was equipped with the CombustionOpt, SCR-Opt, PerformanceOpt, and MaintenanceOpt modules. Unit 2, which is also a cyclone-fired unit, was equipped with the CombustionOpt, SCR-Opt, SootOpt, PerformanceOpt, and MaintenanceOpt modules. Unit 3, a tangentially-fired unit, was equipped with CombustionOpt, SootOpt, and MaintenanceOpt modules.

The reported average NO_x emission reduction of between 12 and 14 percent exceeded the original goal of five percent. This significant reduction in NO_x emissions was attributed to a priority trade-off made by plant personnel that is discussed in detail later in this section. The modules attributed to the NO_x reduction actions were CombustionOpt, SootOpt, and SCR-Opt. An additional benefit was a drop in NH_3 consumption in the selective catalytic reduction (SCR) system.

NeuCo reported that the goal of increasing available megawatt hours (MWhs) by 1.5 percent was met through the information provided by the optimization modules for plant personnel use and by improved process management. The switch from high-sulfur, high-Btu Illinois coal to PRB coal had the potential to lower plant performance because of plant design and operating experience issues. With the optimization modules providing prioritized alerts and knowledge-based diagnostics for a wide array of plant equipment and process anomalies, it is reasonable to assume that the plant was able to avoid some of the unit output derating it might have encountered otherwise. Additionally, the demonstration technology also improved the management of cyclone flame quality through heightened monitoring of cyclone conditions, which likely avoided some degree of unit output derating resulting from cyclone slag build-up.

The goal of demonstrating commensurate reductions in greenhouse gases, mercury (Hg), SO_2, and particulates was achieved because of the improved heat rate brought about by reduced coal consumption.



MaintenanceOpt Workflow for Problem Detection, Diagnosis, and Resolution

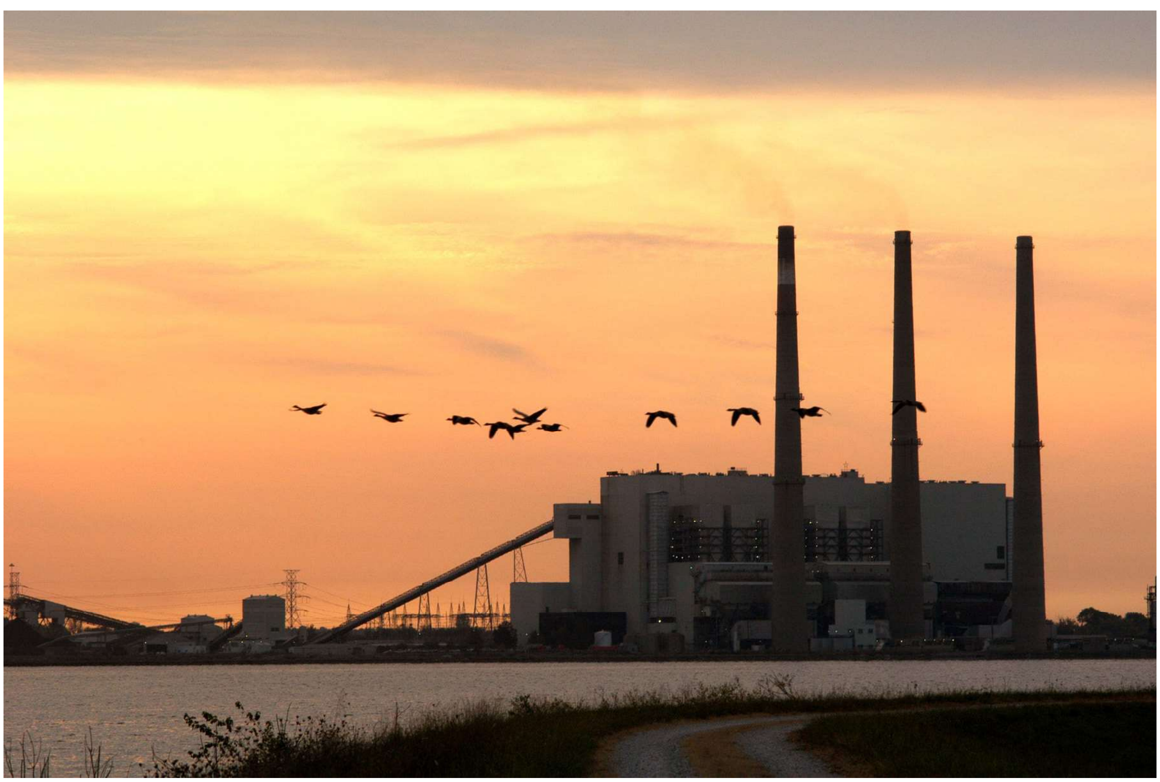
The goal of achieving commensurate increases in profitability resulting from lower costs, improved reliability, and greater commercial availability was achieved as the direct result of the full or partial completion of all other goals. Improvement in plant heat rate resulted in less coal consumption, which ultimately led to reduced costs at constant net output. Also, reducing plant generation derates as a result of both improved operating knowledge and equipment/process management resulted in enhanced plant reliability and availability.

The application of the various performance optimization modules resulted in an overall improvement in plant heat rate of 0.7 percent. The 0.7 percent improvement was roughly half the target because competing priorities prevented full achievement of the goal. The two competing priorities were set by plant personnel. The first was to place a high priority on furnace cyclone stability/availability, as the cyclones were designed to operate with bituminous coal instead of the PRB currently used. The second was to place a higher priority on minimizing NO_x production. Given the flexibility of the modules to exceed the NO_x reduction goal, it is likely that the 1.5 percent heat rate improvement goal would have been achieved had NO_x reduction not been given a higher priority. An additional factor that may have contributed to the lower improvement in heat rate was the deteriorating fuel quality received by the BEC that may have resulted in an actual increase of the baseline heat rate had the optimization packages not been used.

Benefits

The NeuCo project demonstrated an artificial intelligence (AI)-based optimization technology that can be applied to many existing coal-fired power plant boilers as well as boilers fired by other fossil fuels. The modular optimization technology was integrated with plant instrumentation and controls and provided a flexible suite of controls and diagnostic functionality that enhanced plant operations, reduced emissions, and rendered maintenance activity more effective.

The technology demonstrated the ability to respond the priority placed on NO_x reduction by plant personnel by exceeding the NO_x reduction goal while still improving, but not meeting, the heat rate goal. It is believed that, had the objectives been prioritized differently, the project would have achieved the target NO_x reduction and heat rate improvement goals.



Baldwin Energy Complex

ARTIFICIAL INTELLIGENCE

Artificial intelligence (AI) is commonly defined as the science and engineering of making intelligent machines, especially intelligent computer programs. Relative to applications with coal-fired power plants, AI consists of aspects or considerations that deal with the following:

- N
new relationships in the plant environment.
- A
- F
been determined to be sufficiently accurate to meet the needs of plant control systems.

Neural networks (NNs) are a class of algorithms that simulate the operation of biological neurons. The NN learns the relationships among operating conditions, emissions, and performance parameters by processing the test data. In the training process, the NN develops a complex nonlinear function that maps the system inputs to the corresponding outputs. This function is passed on to a mathematical minimization algorithm that finds optimum operating conditions.

Neural networks are composed of a large number of highly interconnected processing elements that work in parallel to solve a specific problem. These networks, with their extensive ability to derive meaning from complicated or imprecise data, can be used to extract patterns and detect trends that are too complex to be detected by either humans or other computer techniques. Neural networks are trainable systems that can "learn" to solve complex problems and generalize the acquired knowledge to solve unforeseen problems. A trained NN can be thought of as an expert in the category of information it has been given to analyze. Neural networks are considered by some to be best suited as advisors, i.e., advanced systems that make recommendations based on various types of data input. These recommendations, which will change as power plant operations change, suggest ways in which plant equipment or technologies can be optimized.

Advanced algorithms, on the other hand, are programmed to incorporate established relationships between input and output information based on detailed knowledge of a specific process. They are used by computers to process complex information or data using a step-by-step, problem-solving procedure. In particular, genetic algorithms provide a search technique to find true or approximate solutions to optimization problems. These algorithms must be rigorously defined for any computational process since an established procedure is required for solving a problem in a finite number of steps. Algorithms must tell the computer what specific steps to perform and in what specific order so that a specified task can be accomplished. Advanced algorithms are now part of the sophisticated computational techniques being successfully applied to power plants to increase plant efficiency and reduce unwanted emissions.

Fuzzy logic (FL), the least specific type of AI software, is equipped with a set of approximate rules used whenever "close enough is good enough." Fuzzy logic is a problem-solving control-system methodology that has been used successfully with large, networked, multi-channel computers or workstation-based data-acquisition and control systems. Fuzzy logic can be implemented via hardware, software, or a combination of both. Elevators and camera auto-focusing systems are primary examples of FL systems. Fuzzy logic stops an elevator at a floor when it is within a certain range, not at a specific point.

Fuzzy logic has proven to be an excellent choice for many control system applications since it mimics human control logic. By using an imprecise but very descriptive language, FL deals with input data much like a human operator. Fuzzy logic is very robust and provides a simple way to arrive at a definite conclusion based upon vague, ambiguous, imprecise, or missing input information. However, while the FL approach to solving control problems mimics human decision-making, FL is much faster. The FL model is empirically based, relying on operator experience rather than technical understanding of the system.

While the heat rate improvement goal was not met, a significant improvement was demonstrated, resulting in a potential fuel cost savings benefit. Further potential savings would be achieved by utilizing the system equipment performance diagnostic capabilities.

The demonstration of NeuCo optimization technology at the BEC resulted in improved reliability, higher output, and lower maintenance costs, but these benefits were difficult to quantify precisely. Environmental conditions and coal properties changes, as well as equipment wear and many other factors, could have obscured some portion of the optimization systems' benefits.

Improved reliability, reduced maintenance costs, and higher efficiency will not only benefit the power plant, but reduce consumer costs while the improved environmental performance contributes to a cleaner environment. The participant validated the technical and cost benefits described above by the sale of 57 optimization packages through December 31, 2011. These sales were all for application on coal-fired units. Although there is no available sales data, the participant has indicated that some of the optimization packages are capable of comparable or better improvements on other fossil fueled generating units.

Conclusions

The five plant optimization products developed and demonstrated during the course of the project have the potential to provide operational, economic, and environmental benefits for many types of power plant boilers. These systems operate with existing control equipment and sensors thus minimizing system installation cost. In addition, installation does not require substantial plant downtime.

NeuCo indicated that the payback period for the demonstration technology is well under a year for a typical U.S. fossil-fired plant. The actual benefits realized and payback period required may vary depending on the circumstances at specific power plants. The performance benefits, low cost, and inherent flexibility of the technology have generated significant interest within the fossil fuel-fired electrical generation industry.

Increasing Power Plant Efficiency: Lignite Fuel Enhancement

Introduction

U.S. lignite coals have a moisture content ranging from 25 to 40 percent, and can require approximately seven percent of the fuel heat input in the furnace to evaporate it. This level of moisture places additional requirements on power plants to compensate for higher fuel flow rates and the subsequent upstream and downstream effects (such as higher processing power requirements, higher maintenance, and lower plant efficiency) when compared to the use of eastern bituminous coals. Despite their high moisture content, western lignite coals, as well as subbituminous coals, are attractive due to their low cost, lower emissions when combusted, and high reactivity.

Coal dewatering and drying processes developed thus far are complex, expensive, and require high-grade heat to remove moisture. Consequently, these processes have not gained industry acceptance. A promising low-temperature coal drying process has been developed by Great River Energy (GRE) that utilizes plant waste heat to reduce the lignite moisture content in a fluidized bed dryer (FBD) at GRE's Coal Creek Station (CCS) in Underwood, North Dakota.

The National Environmental Policy Act (NEPA) requirement for the GRE project was met with an Environmental Assessment and issuance of a Finding of No Significant Impact (FONSI) on January 16, 2004. A Cooperative Agreement was awarded on July 9, 2004. The commercial demonstration completed operations in March 2010. The estimated project costs are $31,512,215. The DOE share is $13,518,737 (43 percent) and the GRE share is $17,993,478 (57 percent).

Coal Creek Station

Project Objectives

The overarching objective of GRE's project was to increase the value of lignite as a fuel by reducing its moisture content using an innovative coal dryer concept that conserved low grade heat from the power plant that would otherwise be discharged to the environment. The Lignite Fuel Enhancement project supported this objective through the demonstration of a 5 to 15 percentage point reduction in lignite moisture content (a moisture content reduction from approximately 40 to 30 percent, which is about 25 percent of the total moisture content) at GRE's CCS.

The project demonstration was conducted in two phases. During Phase 1, a coal dryer prototype was designed and installed at CCS Unit 2 and a testing program was initiated. The objectives of prototype testing were to acquire operating experience with the dryer, confirm pilot results, and quantify the effect of dryer operational parameters so that optimal performance would be achieved. An additional objective was to incorporate the lessons learned during prototype testing into the design of the dryers being installed during Phase 2 of the project. The prototype was operated from 2006 to 2009 to obtain data for the design of full-size dryers.

The Phase 2 project objectives were to design, build, and install a full-scale coal drying system on the nominal 546 MW Unit 2, and to conduct a full-scale, long-term, operational moisture reduction test. The moisture reduction testing included determining the magnitude of Unit 2 efficiency improvement, quantifying the emissions reduction, and assessing the effects of burning dried coal on unit operation.

Project Description

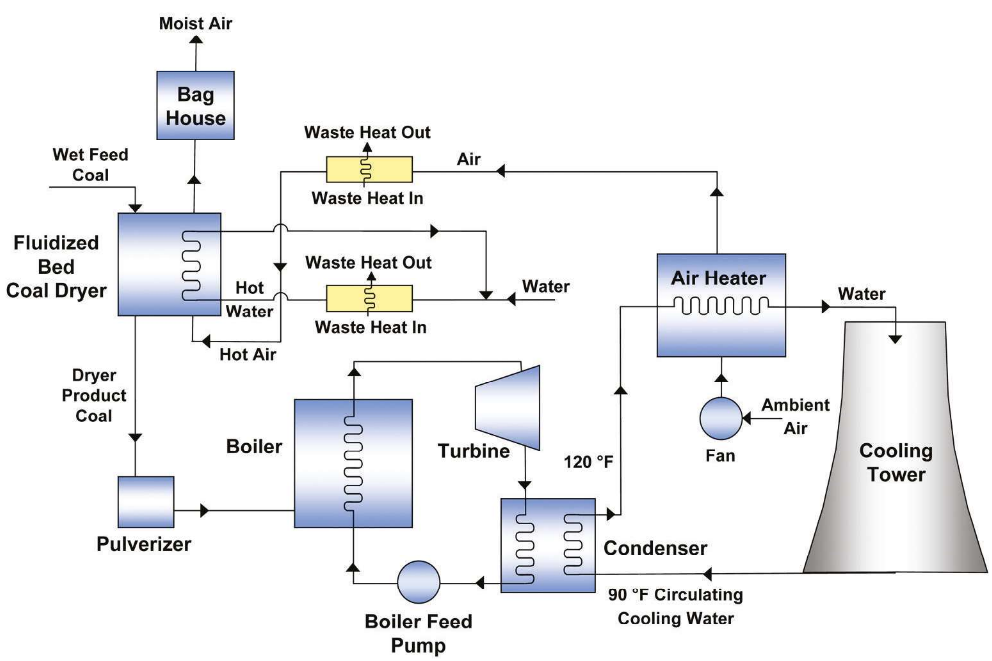
This project has its roots in lignite drying technology R&D conducted by GRE and others since the 1990s. As the R&D work progressed, GRE became convinced of the viability of the lignite drying concept. After identifying a fluidized-bed coal dryer (FBCD) in 2002 as their coal drying technology of choice, GRE submitted an application to DOE under CCPI-1 to continue development of the technology with the commercial demonstration of a prototype FBCD, and, using the lessons learned from the prototype, to develop and install a full-size coal drying system on one unit at CCS. A Cooperative Agreement was negotiated with DOE for funding under CCPI-1 in July 2004.

CCS is a two unit, lignite-fired power plant that supplies electricity to 38 member cooperatives in Minnesota. The plant consists of two identical tangentially fired Combustion Engineering (CE) boilers, each supplying a single steam turbine. Both units are nominally rated at 546 MW. The station burns approximately seven million tons of lignite per year. The design steam conditions are 1,005 degrees Fahrenheit (°F) for main and reheat steam temperature at 2,520 pounds per square inch-absolute (psia) throttle pressure. The CCS has eight pulverizers per unit (seven active and one spare). The station has two single-reheat General Electric G-2 turbines. The plant rejects heat to the environment through three mechanical draft cooling towers. Lignite, with an HHV of 6,200 Btu/lb and total moisture content of approximately 38 percent, is supplied from the nearby Falkirk mine.

In the lignite drying process cooling water leaves the condenser carrying the waste heat rejected by the steam turbine. Before the water reaches the cooling tower, where its heat would normally be discharged to the environment, it first passes through an air heater. In the air heater, a fan-driven air stream picks up some of the waste heat from the cooling water. The heated air is then sent to the FBCD, which is configured for two-stage drying to optimize heat transfer. Before arriving at the FBCD, the air stream picks up additional heat from the unit flue gas through another heat exchanger. The twice-heated air stream then enters the FBCD. After picking up moisture from the coal, the moisture laden air stream passes through a dust collector to remove coal dust liberated during the drying process before being discharged to the atmosphere. Additional heat is added to the FBCD through coils fed with water heated by the unit's flue gas. This additional heat is added to the FBCD to optimize fluidized bed operating characteristics. After leaving the FBCD, dried coal enters a coal storage bunker (not shown) before being sent to a pulverizer for size reduction prior to being delivered to the boiler.

The GRE project at CCS was implemented in two phases. The first phase of the project involved the installation and operation of one prototype dryer, rated at 112.5 tons/hour (225,000 lb/hour) capacity. The prototype dryer was designed to reduce the lignite moisture content from 38 percent to 29.5 percent, which corresponds to an increase in higher heating value from 6,200 Btu/lb to 7,045 Btu/lb.

The prototype coal drying system was designed with completely automated control capability, which included startup, shutdown, and emergency shutdown sequences. The heat input to the FBCD is automatically controlled to remove a specified amount of moisture from the lignite feed stream.



Schematic of Lignite Coal Drying Process

Following the prototype dryer installation and startup, around-the-clock operations and data collection began in March 2006. The moisture content of the lignite processed through the prototype coal drying system was reduced from about 38.5 percent to 29.5 percent. In addition to the measured reductions in SO_x, NO_x, and CO_2 emissions in the flue gas, two modes of Hg reduction were also achieved. First, the heavy components of lignite that were collected in the first stage of the dryer (and removed) possessed a higher Hg concentration, reducing the amount of Hg in the coal fed to the boiler. In addition, Hg oxidation was enhanced as coal moisture was reduced, thereby facilitating additional capture in the flue gas desulfurization unit. Both modes of reduced Hg emissions were confirmed with semi-continuous emission monitors at the inlet and outlet of the flue gas desulfurization unit.

GRE initiated design activities for full-scale dryers (135 tons/hr) in September 2006, which incorporated lessons learned from prototype operation. The full-scale dryer system design was completed in December 2007 and GRE subsequently installed four dryers on Unit 2. Due to the success of the prototype demonstration, GRE installed four more dryers on Unit 1 with its own funds. The final result was that Unit 1 and Unit 2 of the CCS were simultaneously retrofitted with lignite coal dryers.

Fabrication and on-site assembly were finished in May 2008 and major dryer internal components for the Unit 2 dryers were completed by December 2008. GRE completed the construction of the dryer system and began testing in late 2009.

Results

The project achieved the goal of lowering the moisture content of the lignite by 8.5 percentage points (approximately one fourth of the as-received moisture). Test results were obtained from the technology installed on Unit 1, which is identical to that of Unit 2. Unit 2 was out of service at the time of testing for reasons not associated with the lignite drying technology. During performance testing, Unit 1 provided the combined station load for Units 1 and 2 while also supplying extraction steam for an auxiliary process. This plant configuration resulted in an efficiency impact to the testing results that could not be accurately extrapolated to periods of normal operation. While those particular data could not be obtained by GRE, other data for moisture reduction and emissions were obtained.

The demonstrated 8.5 percent moisture reduction of the lignite resulted in an HHV improvement in the fuel from 6290 Btu/lb to 7043 Btu/lb. Also demonstrated were emissions reductions in Hg by 41 percent, NO_x by 32 percent, and SO_2 by 54 percent.

Benefits

Reducing the coal moisture content improved the lignite HHV, which arguably reduced unit heat rate. This improvement was due primarily to lower stack loss and decreased auxiliary power use (e.g., lower fan, pulverizer, cooling tower, and coal handling power). As the boiler efficiency increases and the auxiliary power requirement was reduced, additional electrical energy was available for export to the grid. The reduction in coal flow rate also produced an incremental improvement in coal handling and processing equipment wear rates, which resulted in a maintenance-related cost benefit.

Performance of the back-end environmental control systems (i.e., electrostatic precipitator) also improved with the use of reduced moisture coal in the furnace. The reduction in coal flow rate to the boiler resulted in a lower flue gas flow rate that gave the flue gas a longer residence time within the emissions control equipment, incrementally improving its performance. Similarly, the reduction in required coal-flow rate to the boiler and the resulting modified temperature profile within the boiler directly translated into lower emissions of NO_x, SO_2, and particulates. While not directly measured, CO_2 emissions were calculated to have been decreased by approximately 3.8 percent. Units equipped with wet scrubbers also exhibited a reduction in Hg emissions resulting from firing reduced moisture coal. This reduction resulted from an increase in the oxidation of elemental Hg to forms that can be removed in a scrubber.

A potential benefit of the coal drying system for new plants would be a reduction in capital costs. A decrease in the coal firing rate could result in smaller capacity requirements for coal handling and coal processing systems as well as those associated with combustion, flue gas transport, and flue gas cleaning.

The potential market for GRE's coal-drying technology is significant. Currently, more than 100 GW of U.S. installed capacity is burning coal with inherently high moisture content. This technology could not only reduce emissions from coal-fired power plants, but also extend abundant U.S. coal supplies, thereby enhancing the nation's energy security.

In 2009, GRE signed an agreement with Worley Parsons, an engineering firm, giving them preferred engineer status to license DryFining™, the trademark name for the technology. GRE will also process and ship DryFined coal to the Spiritwood Station nearing completion 10 miles east of Jamestown, North Dakota. By the conclusion of the project, GRE had 120 confidentiality agreements signed by vendors and suppliers of equipment and 19 by utilities. Companies in the United States, Canada, Australia, China, India, Indonesia, and Europe have signed GRE confidentiality agreements. These agreements are required before GRE will provide details of the technology to interested parties. In addition, three preliminary evaluations have been completed that show the comparative improvements that can be realized at those stations. DryFining™ earned the "Best Coal-Fired Project" award for 2010 from the editors of the prestigious *Power Engineering* magazine.

Conclusions

The operation of full-scale lignite drying equipment was demonstrated and the remaining project performance goals were met, which included an improvement in lignite quality and the reduction of emissions.

TOXECON™ Retrofit for Mercury and Multi-Pollutant Control on Three 90 MW Coal-Fired Boilers

Introduction

Powder River Basin (PRB) coal has become widely used and is typical of other western subbituminous coals in that it produces a high percentage of elemental mercury (Hg) in the flue gas upon combustion. Elemental Hg is more difficult to remove from the flue gas stream than solid state oxides of Hg (the form more common in bituminous coals). The injection of powdered activated carbon (PAC) into the flue gas stream for Hg capture is one promising control technology.

A potential disadvantage of injecting PAC for Hg control in plants where PAC injection occurs upstream of the particulate control system is its impact on the salability of ash for making concrete. If the ash cannot be sold, it must be sent to a landfill, which increases the plant's operating costs and decreases available disposal capacity. The TOXECON™ configuration injects the activated carbon downstream from the primary ash collection equipment, thus ensuring the ash remains acceptable for sale.

DOE selected the TOXECON™ technology in 2003 as a CCPI-1 Hg control demonstration project. The demonstration was carried out at Wisconsin Electric Power Company's (We Energies) Presque Isle Power Plant (PIPP) located in Marquette, Michigan.

The total project cost was $47,512,830 with DOE providing $23,756,415 or 50 percent. We Energies provided the remaining 50 percent. NEPA was satisfied with a FONSI in September 2003. The demonstration began operation in January 2006 and was completed in September 2009.

Typical PRB Coal Analysis

Property	Typical Value
Higher Heating Value, Btu/lb	9,052
Analysis, Weight Percent	
Moisture	25.85
Carbon	52.49
Hydrogen	3.65
Nitrogen	0.75
Sulfur	0.28
Ash	4.64
Oxygen	12.33
Chlorine	0.01

Project Objectives

The project objectives were to demonstrate, over the long-term (three years), 90 percent removal of Hg from power plant flue gas using activated carbon injection; demonstrate a reliable Hg continuous emission monitoring system (CEMS) suitable for use in flue gas created by coal-fired power plants; advance commercialization of the technology through successful operation and integration with the power plant; evaluate trona (a naturally occurring sodium bicarbonate mineral) injection to reduce NO_x and capture 70 percent of SO_2 emissions via the new bag house; demonstrate recovery of Hg from the spent sorbent; reduce particulate matter (PM) emissions via the new bag house; and allow the continued reuse and sale of fly ash captured by the existing hot-side ESP.

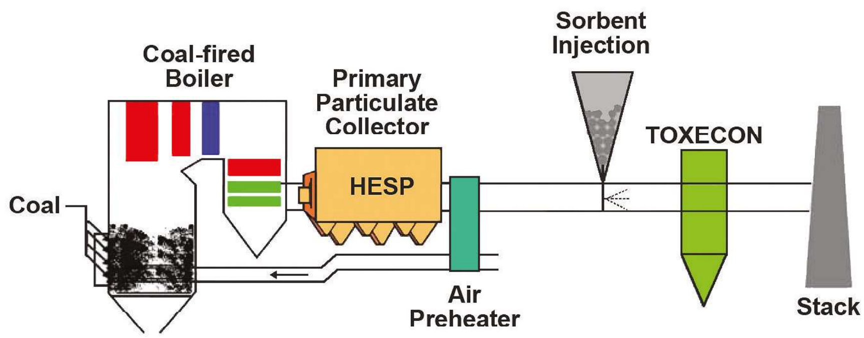
Project Description

The TOXECON™ demonstration technology was installed on the combined flue gas streams of PIPP Units 7, 8, and 9, which are rated at 90 MW each. There are a total of nine units at the PIPP site that were installed between 1955 and 1979. Units 7, 8, and 9 are of the Riley Turbo design and are dry-bottom, opposed-wall-fired boilers. Steam conditions at the superheater are 1625 psig and 1005 °F, and conditions at the reheater are 390 psig and 1005 °F. Each of the three units is equipped with Joy-Western hot side electrostatic precipitators (ESPs). NO_x emissions are managed with low-NO_x burners and a combustion optimization software package. SO_2 emission limits are met on Units 7, 8, and 9 by burning low sulfur PRB coal. The coal typically has an HHV of 9,052 Btu/lb, a sulfur content of 0.28 percent, and an average Hg content of 0.13µg/g.

For the demonstration at PIPP, the TOXECON™ technology was installed downstream of the air preheater. The TOXECON™ process consisted of two systems that included (1) a sorbent injection system that includes the in-duct injection lances and the sorbent receiving, handling, and storage facilities; and (2) a baghouse with secondary systems for ash removal and supplying compressed air for bag cleaning.

The TOXECON™ technology is intended for installation in a downstream location from an existing cold-side or hot-side ESP. When applied to a host plant that is configured with a hot-side ESP, the TOXECON™ system is installed immediately downstream of the air preheater. In the case of a cold-side ESP installation, the TOXECON™ system is located just downstream of the ESP.

Presque Isle Power Plant



TOXECON™ Flow Schematic at PIPP

The TOXECON™ installation at PIPP was relatively simple. The PAC system consisted of storage, transport, and injection subsystems. Because the PIPP installation includes a hot-side precipitator, PAC is injected downstream from each of Units 7, 8, and 9 air preheaters through three separate trains. The design and location of the PAC injection lances ensure thorough mixing of the PAC sorbent with the flue gas.

Each of the three PAC duct injection trains handled 200 lb/hr of sorbent material and consisted of a feed hopper, feeder, eductor, injection lance, and blower. The design injection rate of 216 lb/hr permitted optional reinjection of some PAC/fly ash from the baghouse. A similar injection train was also installed to evaluate the effectiveness of a sodium-based sorbent for the removal of 70 percent of SO_2 as well as some NO_X. After the sorbents were injected into the flue gas from Units 7, 8, and 9, the flows were directed to a single duct leading to the baghouse. Flue gas leaving the baghouse splits into three streams and is discharged through three separate flues enclosed by a single stack.

The PAC entrained in the flue gas captured some of the Hg present as the gas stream traveled to the baghouse. Once in the baghouse, the PAC and residual fly ash were removed from the gas stream by forming a dust cake layer on the surface of the bags. The PAC in the dust cake continued to remove Hg from the gas stream as long as it remained on the bags, which was also the case when sodium-based sorbent was used for SO_2 and NO_X control. Because removing the dust cake layer

TOXECON™ System Installed at PIPP

reduced collection efficiency, the design and operation of the baghouse maximized the amount of time the dust cake remained on the bags within the limits of sound operating practices.

At the beginning of the project in 2003, there were no Hg continuous emission monitors (CEMs) available that had Environmental Protection Agency (EPA) certification and could be operated independent of full-time technical support. As part of the project, Hg CEMs were developed and tested that could be reliably used in the power plant environment and measure Hg with good sensitivity.

Two thermal laboratory-scale technologies having the potential to remove Hg from TOXECON™ baghouse ash were identified during the first quarter of 2008. One of the processes used microwave energy as the energy source while the other used heated air. Both methods were reported to exceed 90 percent recovery of Hg from the baghouse ash in laboratory tests.

One laboratory study irradiated ash with microwave energy for three minutes under a nitrogen gas flow. The evaporated Hg was carried by the gas flow to a condenser. Mercury that was not condensed was scrubbed from the nitrogen with a potassium permanganate solution.

The second technology used a chemical absorbent to chemically capture Hg while it was in the gas phase. The chemical absorbent developed for this study exhibited excellent Hg capture performance; however, it proved too expensive for commercial applications. Subsequently, a commercially produced absorbent was identified and tested. The commercially available absorbent captured the Hg that was released from the fly ash by thermal desorption. The resulting sorbent/Hg material was found to be both thermally and chemically stable, presenting no risk to the environment.

Results

TOXECON™ performance testing confirmed a reliable minimum Hg removal rate of 90 percent from the flue gas leaving the hot-side ESP. This performance was verified using several different types of PAC. During testing, Hg removal was observed to vary inversely (linear) with baghouse temperature, which is a well-documented correlation in the TOXECON™ baghouse.

The goal of developing a reliable Hg CEM capable of operating in a power plant environment was met. Toward the conclusion of the demonstration, the CEM developed by Thermo Fisher and ADA-ES exhibited high availability for monitoring Hg at the inlet and outlet duct. It is commercially available from Thermo Fisher and has reportedly been selling well.

The baghouse and associated equipment were successfully integrated into plant operations. The spent PAC handling equipment was upgraded and the operation of the system was optimized during the demonstration project. Early in the project, there was a problem with hot embers/fires in the baghouse hoppers. A combination of laboratory work and operational adjustments corrected the problem and there was no recurrence during long-term testing.

Sulfur dioxide and potential NO_X removal rates were investigated by injecting trona ($Na_3H(CO_3)_2 \cdot 2H_2O$), a sodium-based sorbent, into the flue gas stream. While the goal of 70 percent SO_2 removal was met, there was no perceptible impact on NO_X emissions. When both trona and PAC were injected simultaneously, Hg removal efficiency decreased significantly, with a slight (approximately one percent) effect on opacity. Even with an increase in the brominated PAC injection rate [1.5 lb/MMacf (million actual cubic feet) to 4.5 lb/MMacf], achieving 90 percent Hg control while maintaining 70 percent SO_2 removal could not be consistently achieved.

The goal to recover 90 percent of Hg captured in the sorbent was met in laboratory tests. The Hg content in the consumed sorbents was reduced from 14.8 ppm to 0.252 ppm (98.3 percent reduction) after the microwave treatment methodology, which was one of the two methods identified to accomplish this goal. The other process used a natural gas-fired kiln and reduced the Hg content from 31 ppm to a level that was not measureable. The Hg released during these tests was captured by another process, leaving the sorbent and fly ash to be constructively reused.

The goal of increasing the plant's collection efficiency of PM [particularly for $PM_{2.5}$ (particulate matter less than 2.5 microns in diameter)] was met due to the high capture efficiency of the baghouse.

The utilization goal for fly ash captured in the hotside ESP was met due to the introduction of PAC downstream of the primary particulate control device. While the actual utilization of fly ash was outside the scope of the project, the project goal to enable fly ash utilization by preserving its quality was met.

CONTROLLING MERCURY

While research continues to find better and cheaper ways to remove mercury from the flue gas of coal-fired boilers, electric generating units (EGUs) already have several viable options. The mercury found in flue gas can be found in several physical and/or chemical states. It can be in the form of elemental mercury vapor or in an oxidized state. These chemical states can either be attached to fly ash particles or free-floating. No matter which technology is used, elemental mercury is more difficult to remove than oxidized mercury.

The current leading technology specific to mercury removal consists of injecting powdered activated carbon (PAC) into the flue gas to adsorb the mercury. In some cases, the system itself is very simple, consisting of equipment to receive, handle, store, and inject the carbon. The carbon is injected into the flue gas between the air heater and the particulate control device. The particulate control device, either a baghouse or an electrostatic precipitator, removes the carbon and adsorbed mercury along with the fly ash. Continued use of the existing baghouse or ESP assumes that the existing particulate control device can handle the additional particulate load without degradation of performance. A disadvantage of this simple system is that the fly ash is contaminated with activated carbon. In 2004, approximately 40 percent of the fly ash was sold for constructive uses. Fly ash with high carbon content is difficult to sell and EGU operators are reluctant to risk losing their market, since they would incur disposal costs rather than receive payment for the fly ash. If the boiler being retrofitted with activated carbon injection (ACI) is equipped with a hot-side ESP, the power plant can install the ACI system downstream of the air heater and install a new particulate removal system to remove the PAC and any residual fly ash. A baghouse is generally preferred due to its high efficiency, especially for respirable particulates. This method ensures that the bulk of the fly ash removed by the existing ESP is not contaminated with additional carbon.

While ACI is the most effective method of capturing mercury, power plants can often achieve significant coincidental mercury removal with their particulate and SO2 controls. The effectiveness of achieving adequate mercury removal in equipment intended to control other pollutants varies significantly from plant to plant. As stated above, elemental mercury is less likely to be captured by any removal system, although ACI is less sensitive to the state of the mercury. The state of mercury in flue gas is affected by the type of boiler and coal and variations in boiler operation. Operators can influence the state of mercury in the boiler by optimizing combustion conditions to maximize oxidation of the mercury while maintaining satisfactory overall operation. By increasing the portion of the mercury that is oxidized, its removal in the ESP, baghouse, and/or flue gas desulfurization (FGD) system is enhanced.

Increased oxidation of mercury is also a co-benefit of a selective catalytic reduction (SCR) system. The SCR catalyst tends to oxidize a portion of the mercury in the flue gas, leading to higher removal rates in the particulate control system and/or the FGD system.

Benefits

The TOXECON™ process provides a technology pathway to significant Hg control and has the potential to widen the use of PRB, as well as other western subbituminous coals, especially in light of the Mercury and Air Toxics Standards (MATS) established in December 2011. Additional benefits are derived from the inherently high particulate removal efficiency of a baghouse. While trona injection resulted in a 70 percent reduction of SO_2, concurrent PAC/trona injection greatly reduced previously demonstrated Hg removal efficiency. However, it is anticipated that other sorbents will be able to be used to further control pollutants and be complementary to Hg removal efficiency.

The TOXECON™ process was configured to treat the plant flue gas after the bulk of fly ash is captured in the HESP, thus preserving its quality for use as a concrete additive as well as for other beneficial uses. A secondary benefit is the preservation of landfill capacity, as the fly ash will have a beneficial use and not require disposal.

As part of the TOXECON™ process design, the baghouse downstream of an existing ESP removes the injected sorbent and the adsorbed pollutants. An additional benefit of this configuration is the significant reduction of both $PM_{2.5}$ and $PM_{2.5}$ precursor emissions (e.g., SO_2).

Contacts for Participants in CCT Projects

John McDermott,
Vice President, Product Management
NeuCo, Inc.
33 Union Street, Floor #4
Boston, MA 02108
617-587-3198
mcdermott@neuco.net

Charles Bullinger
Great River Energy
2875 Third St., SW
Underwood, ND 58576-9659
701-442-7662
cbullinger@grenergy.com

Steven T. Derenne,
Project Manager
Wisconsin Electric Power Company
333 West Everett Street
Milwaukee, WI 53203
414-221-4443
steve.derenne@wepowerllc.com

The TOXECON™ process is considered suitable for application on 167 GW of coal-fired generating capacity and may prove to be the primary Hg control choice for western coals, especially when fired in units having hot-side ESPs. TOXECON™ systems were installed at seven plants in addition to PIPP. Although exact numbers are not available, it has been reported that a substantial market has developed for the Hg CEMS developed during this project. When the CAMR was vacated by the courts, there was uncertainty regarding the final Hg rule, which likely led to power plants deferring their decision on the selection of an Hg control technology. The final standards for Hg were published in mid-February 2012. The success of the TOXECON™ demonstration has provided the owners of those 167 GW with a viable technology to meet the three year deadline for compliance with the new Hg standard.

Conclusions

The TOXECON™ process demonstrated significant Hg control for units having a hot-side ESP and firing a western subbituminous coal. The technology should be applicable to all coal-fired power plants. The placement of the TOXECON™ baghouse downstream of the existing ESP preserved fly ash quality for beneficial use while removing Hg from the plant flue gas stream. Fly ash that is used constructively will not require disposal in a landfill, thereby eliminating disposal costs and conserving landfill space. The baghouse also removed much of the very fine particulate that passed through the ESP.

CCPI-1 Program Conclusions

The goal of CCPI-1 was to "*advance technology related to coal-based power generation that results in efficiency, environmental, and economic improvement compared to currently available state-of-the-art alternatives*." The three projects discussed in this report have directly contributed to the CCPI objectives through more efficient operation that extends the nation's abundant coal reserves, further reduces emissions, resulting in cleaner air, and lowers generation costs, which can help to keep electricity affordable. Below is a brief summary of the contributions of each CCPI-1 project.

- The plant optimization capability developed during the course of the Demonstration of Integrated Optimization Software at the Baldwin Energy Complex project could benefit many types of power plant boilers. The NO_x reduction target of five percent was exceeded and actually reached the 12 to 14 percent range, while heat rate improvement only reached half of the targeted improvement. However, the improvement achieved in heat rate should translate into slightly lower fuel consumption (and hence fuel cost) with a commensurate decrease in overall emissions. The demonstrated environmental, efficiency, and cost improvements confirm that the project has met the CCPI-1 program goals.

- The GRE Increasing Power Plant Efficiency: Lignite Fuel Enhancement demonstration has shown benefits from the full-scale coal drying system at Coal Creek Station (CCS) that utilizes waste heat. Lignite quality has improved and plant emissions have decreased due to a reduction in the amount of lignite being burned and the reduced Hg content of the fuel brought about by the density separation in the first drying stage. An additional benefit for new plants could be a reduction in capital costs due to subsystems being favorably impacted by decreased plant fuel requirements. These advancements demonstrate that CCPI-1 program goals have been achieved.

- TOXECON™ Retrofit for Mercury and Multi-Pollutant Control on Three 90-MW Coal-Fired Boilers controls Hg and other pollutants in the flue gas stream with sorbent injection while preserving the marketability of the captured fly ash. A reliable Hg CEM, capable of withstanding harsh power plant conditions, was also developed during this project. The results obtained from this project contribute to the achievement of the CCPI-1 program goals.

The application of technologies resulting from the DOE CCPI-1 solicitation will help resolve environmental concerns regarding the increased use of coal. These contributions to coal's viability will help ensure that the United States continues to generate clean, reliable, and affordable electricity from this plentiful and valuable resource.

DOE Contacts for CCT Projects

Michael McMillian,
Project Manager
TOXECON™
National Energy Technology Laboratory
3610 Collins Ferry Road
P.O. Box 880
Morgantown, WV 26507-0880
304-285-4669
michael.mcmillian@netl.doe.gov

Sai Gollakota,
Project Manager
Lignite Fuel Enhancement
National Energy Technology Laboratory
3610 Collins Ferry Road
P.O. Box 880
Morgantown, WV 26507-0880
304-285-4151
sai.gollakota@netl.doe.gov

George Pukanic,
Project Manager (ret.)
Demonstration of Integrated
Optimization Software
National Energy Technology Laboratory
626 Cochrans Mill Road
P.O. Box 10940
Pittsburgh, PA 15236-0940
412-386-6085
george.pukanic@netl.doe.gov

Frederick Sudhoff,
Project Manager
Demonstration of Integrated
Optimization Software
National Energy Technology Laboratory
3610 Collins Ferry Road
Morgantown, WV 26507-0880
Phone (304) 285-4560
fred.sudhoff@netl.doe.gov

Bibliography

Sarunac, Nenad, Ness, Mark and Bullinger, Charles. "One Year of Operating Experience with a Fluidized Bed Dryer at Coal Creek Generating Station." 3rd International Conference on Clean Coal Technologies for Our Future, Sardinia, Italy, May 2007. http://www.netl.doe.gov/technologies/coalpower/cctc/ccpi/pubs/GRE/GRE%20Clean%20Coal%20Conf%20Sardinia%20Paper%20May%202007_1.pdf.

Bullinger, Charles, Ness, Mark and Armor, Tony. "Coal Creek Prototype Fluidized Bed Dryer: Performance Improvements, Emissions Reduction, and Operating Experience," EPRI's Coal Fleet for Tomorrow Meeting, San Francisco, CA February, 2007. http://www.netl.doe.gov/technologies/coalpower/cctc/ccpi/pubs/GRE/GRE%20Presentation%20EPRI%20Meeting%20February%202007_1.pdf.

James, Rob., John McDermott, Sanjay Patnaik, and Steve Piché. "Demonstration of Integrated Optimization Software at the Baldwin Energy Complex," Final Report. September, 2008. http://www.netl.doe.gov/technologies/coalpower/cctc/ccpi/pubs/41768R016.pdf.

Derenne, Steven T., "TOXECON™ Retrofit for Mercury and Multi-Pollutant Control on Three 90 MW Coal-Fired Boilers," Quarterly Technical Progress Report, Reporting Period: January 1, 2009–March 31, 2009. April, 2009. http://www.netl.doe.gov/technologies/coalpower/cctc/ccpi/pubs/41768R016.pdf.

U.S. Department of Energy, Office of Fossil Energy, National Energy Technology Laboratory. "Clean Coal Power Initiative (CCPI) Fact Sheet," December 2006. http://www.netl.doe.gov/publications/factsheets/program/Prog052.pdf

U.S. Department of Energy, Office of Fossil Energy, National Energy Technology Laboratory. "Clean Coal Power Initiative (Status Report and Program Review)," Project Brief, April 2004. http://www.netl.doe.gov/technologies/coalpower/cctc/ccpi/pubs/CCPI%20%28Status%20Report%20and%20Program%20Review%29.pdf.

U.S. Department of Energy, Office of Fossil Energy, National Energy Technology Laboratory. "Demonstration of Integrated Optimization Software at the Baldwin Energy Complex," A DOE Assessment, September 2008. http://www.netl.doe.gov/technologies/coalpower/cctc/ccpi/pubs/NeuCo%20PPAfinal%20%20091108_1.pdf.

U.S. Department of Energy, Office of Fossil Energy, National Energy Technology Laboratory. "Demonstration of Integrated Optimization Software at the Baldwin Energy Complex," Project Brief, March 2009. http://www.netl.doe.gov/technologies/coalpower/cctc/ccpi/project_briefs/NeuCo.pdf.

U.S. Department of Energy, Office of Fossil Energy, National Energy Technology Laboratory. "Demonstration of Integrated Optimization Software at the Baldwin Energy Complex," Project Fact Sheet, December 2008. http://www.netl.doe.gov/publications/factsheets/project/Proj221.pdf.

U.S. Department of Energy, Office of Fossil Energy, National Energy Technology Laboratory. "Clean Coal Technology Programs: Program Update 2006, Status as of June 2006." September, 2006, http://www.netl.doe.gov/technologies/coalpower/cctc/ccpi/pubs/2006_program_update.pdf.

U.S. Department of Energy, Office of Fossil Energy, National Energy Technology Laboratory. "Lignite Fuel Enhancement," A DOE Assessment, April 2011. http://www.netl.doe.gov/technologies/coalpower/cctc/topicalreports/pdfs/GRE-PPA%204-12-2011.pdf.

U.S. Department of Energy, Office of Fossil Energy, National Energy Technology Laboratory. "Lignite Fuel Enhancement," Project Brief, March 2009. http://www.netl.doe.gov/technologies/coalpower/cctc/ccpi/project_briefs/Lignite%20Fuel%20Enhancement.pdf.

U.S. Department of Energy, Office of Fossil Energy, National Energy Technology Laboratory. "Increasing Power Plant Efficiency: Lignite Fuel Enhancement," Project Fact Sheet, September 2008. http://www.netl.doe.gov/publications/factsheets/project/Proj219.pdf.

U.S. Department of Energy, Office of Fossil Energy, National Energy Technology Laboratory. "Mercury Control Demonstration Projects, Topical Report #26," February 2008. http://www.netl.doe.gov/technologies/coalpower/cctc/topicalreports/pdfs/topical26.pdf

U.S. Department of Energy, Office of Fossil Energy, National Energy Technology Laboratory. "Power Plant Optimization Demonstration Projects, Topical Report #25," January 2008. http://www.netl.doe.gov/technologies/coalpower/cctc/topicalreports/pdfs/topical25.pdf.

U.S. Department of Energy, Office of Fossil Energy, National Energy Technology Laboratory. "Energy Department Approves Full-Scale Demonstration of Coal Dryer," Fossil Energy Techline, November 2006. http://www.fossil.energy.gov/news/techlines/2006/06066-Coal_Dryer_Demonstration_Begins.html.

U.S. Department of Energy, Office of Fossil Energy, National Energy Technology Laboratory. "TOXECON™ Retrofit for Mercury and Multi-Pollutant Control on Three 90 MW Coal-Fired Boilers," Project Fact Sheet, October 2008. http://www.netl.doe.gov/publications/factsheets/project/Proj224.pdf

U.S. Department of Energy, Office of Fossil Energy, National Energy Technology Laboratory. "TOXECON™ Retrofit for Mercury and Multi-Pollutant Control on Three 90 MW Coal-Fired Boilers," Project Brief, April 2009. http://www.netl.doe.gov/technologies/coalpower/cctc/ccpi/project_briefs/Toxecon.pdf

Acronyms and Abbreviations

ACI	Activated Carbon Injection
AI	Artificial Intelligence
ARRA	American Recovery and Reinvestment Act
BEC	Baldwin Energy Complex
BTU	British thermal unit
CAAA	Clean Air Act Amendments
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CCPI	Clean Coal Power Initiative
CCS	Coal Creek Station
CCT	Clean Coal Technology
CCTDP	Clean Coal Technology Demonstration Program
CE	Combustion Engineering
CEM	Continuous Emissions Monitor
CO_2	Carbon dioxide
DOE	Department of Energy
EA	Environmental Assessment
EPRI	Electric Power Research Institute
EPA	Environmental Protection Agency
ESP	Electrostatic Precipitator
FBCD	Fluidized Bed Coal Dryer
FBD	Fluidized Bed Dryer
FE	Office of Fossil Energy
FGD	Flue Gas Desulfurization
FL	Fuzzy Logic
FONSI	Finding of No Significant Impact
g	Gram
GRE	Great River Energy
GW	Gigawatt
HAPS	Hazardous Air Pollutants
Hg	Mercury
HHV	Higher Heating Value
ICR	Information Collection Request
Lb	Pound
MATS	Mercury and Air Toxics Standards
MMacf	million actual cubic feet
NAS	National Academy of Sciences
NEPA	National Environmental Policy Act
NETL	National Energy Technology Laboratory
NH_3	Ammonia
NN	Neural Network
MW	Megawatts
MWh	Megawatt-hours
NO_x	Nitrogen Oxides
PAC	Powdered Activated Carbon
PIPP	Presque Isle Power Plant
PM	Particulate Matter
$PM_{2.5}$	Particulate Matter less than 2.5 microns in diameter
PPII	Power Plant Improvement Initiative
PRB	Powder River Basin
PSIA	Pounds per Square Inch Absolute
R&D	Research & Development
SCR	Selective Catalytic Reduction
SO_2	Sulfur dioxide
µg	Microgram
U.S.	United States
We Energies	Wisconsin Electric Power Company

National Energy Technology Laboratory

1450 Queen Avenue SW
Albany, OR 97321-2198
541-967-5892

2175 University Avenue South, Suite 201
Fairbanks, AK 99709
907-452-2559

3610 Collins Ferry Road
P.O. Box 880
Morgantown, WV 26507-0880
304-285-4764

626 Cochrans Mill Road
P.O. Box 10940
Pittsburgh, PA 15236-0940
412-386-4687

13131 Dairy Ashford, Suite 225
Sugar Land, TX 77478
281-494-2516

Visit the NETL website at:
www.netl.doe.gov

Customer Service:
1-800-553-7681

U.S. DEPARTMENT OF ENERGY | Office of Fossil Energy

Printed in the United States on recycled paper

June 2012

IN THE UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

STATE OF NORTH DAKOTA, STATE OF WEST VIRGINIA, STATE OF ALASKA, STATE OF ARKANSAS, STATE OF GEORGIA, STATE OF IDAHO, STATE OF INDIANA, STATE OF IOWA, STATE OF KANSAS, COMMONWEALTH OF KENTUCKY, STATE OF LOUISIANA, STATE OF MISSISSIPPI, STATE OF MISSOURI, STATE OF MONTANA, STATE OF NEBRASKA, STATE OF OKLAHOMA, STATE OF SOUTH CAROLINA, STATE OF SOUTH DAKOTA, STATE OF TENNESSEE, STATE OF TEXAS, STATE OF UTAH, COMMONWEALTH OF VIRGINIA, AND STATE OF WYOMING, *Petitioners*, v. U.S. ENVIRONMENTAL PROTECTION AGENCY, *Respondent*.	Case No. 24-1119

DECLARATION OF CLAIRE VIGESAA
IN SUPPORT OF PETITIONERS' MOTION TO STAY FINAL RULE

I, Claire Vigesaa, hereby declare and state under penalty of perjury that the following is true and correct to the best of my knowledge and is based on my personal knowledge or information available to me in the performance of my official duties:

1. My name is Claire Vigesaa, and my business address is 600 East Boulevard Ave Dept 405 Bismarck, ND 58505-0840. I am over the age of 18, have personal knowledge of the subject matter, and am competent to testify concerning the matters in this declaration.

2. I have served as Executive Director of the North Dakota Transmission Authority (NDTA) since July 2023. I have a Bachelor of Science degree in engineering from North Dakota State University and held leadership roles in the electric utility industry for 39.5 years, my last 10 years as General Manager/CEO of an electric transmission cooperative utility. As Executive Director of the NDTA, my responsibilities include working with the North Dakota Industrial Commission (NDIC) to facilitate the development and maintenance of electric transmission infrastructure in North Dakota and coordinating with regional transmission organizations to provide for a reliable and resilient electrical grid.

3. The NDTA was created by the North Dakota legislature in 2005. The NDTA was established to serve as a catalyst for new investment in transmission by facilitating, financing, developing, or acquiring transmission to accommodate energy production. NDTA is actively engaged in seeking ways to improve North Dakota's energy export and transmission capabilities within the state. NDTA is also involved with planning and studying grid reliability, resilience, and congestion issues. To that end, NDTA has funded several studies that examine the likely impacts of EPA's proposed air quality regulations on electric grid reliability and resilience in North Dakota and surrounding regions.

4. I am submitting this declaration in support of Petitioners' Motion to Stay the Final Rule published by the U.S. Environmental Protection Agency (EPA) on May 7, 2024, entitled "National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric

Utility Steam Generating Units Review of the Residual Risk and Technology Review," 89 Fed. Reg. 38508 (Final Rule).

5. As Director of the NDTA, I have significant concerns that the Final Rule will fundamentally undermine the reliability and resiliency of the electric grids upon which the State of North Dakota and its people rely.

North Dakota's Power Generation Environment

6. North Dakota has a diverse portfolio of power generation resources, including wind, coal, hydroelectric, and natural gas. The combined total capacity of all types of utility-scale generation in North Dakota is approximately 8,863 MW, and almost half of that (4,048 MW) comes from 10 coal-firing power plants operating within the State.

7. Over thirty percent of the electricity generated in North Dakota is exported out of the State through the two Regional Transmission Organizations that service the State and surrounding regions—the Midcontinent Independent System Operator (MISO) and the Southwest Power Protocol (SPP).

8. Studies commissioned by the NDTA project a 10,000 GWhr increase in energy demand in North Dakota over the next two decades, requiring approximately 2200 to 2500 MW of additional capacity to meet the anticipated growth in demand.

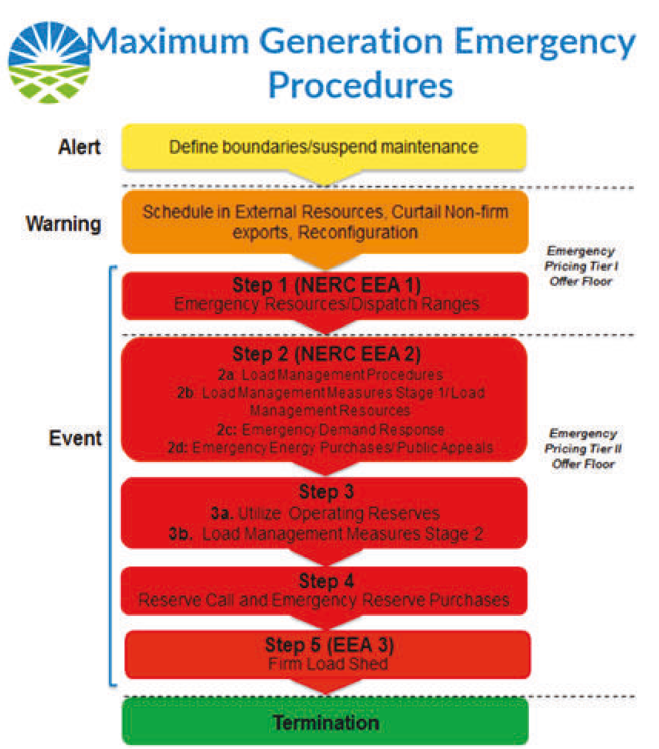
9. The projected growth in renewable resources over the next two decades will not be enough to meet the projected demand in growth, especially if existing dispatchable fossil generation is forced into early retirement by this Final Rule or other federal rules.

10. Dispatchable energy is energy that is available on demand. Energy sources such as wind and solar are considered non-dispatchable. When demand for electricity exceeds the dispatchable supply, the foreseeable result will be blackouts or energy rationing.

<u>The Final Rule Threatens an Already Vulnerable Power Grid</u>

11. The power grids providing electricity to North Dakota (and much of the country) are already stretched dangerously thin, and they do not have the resiliency or the buffer of excess dispatchable generation that they had ten or even five years ago.

12. Prior to 2016, MISO had <u>no</u> instances requiring the use of emergency procedures, but since then, there have been <u>48</u> Maximum Generation events.[1] Maximum Generation events are a multi-tiered process to respond to generation resource shortages. A graphic from MISO shows this tiered process.[2]



---

[1] North Dakota Industrial Commission and North Dakota Transmission Authority, "Analysis of Proposed EPA MATS Residual Risk and Technology Review and Potential Effects on Grid Reliability in North Dakota," at 9 (Apr. 2, 2024) (MATS Study), *available at* https://www.ndic.nd.gov/sites/www/files/documents/Transmission-Authority/Publications/MATS_Analysis_Report.pdf.

[2] Midcontinent Independent System Operator, "Overview of June 10, 2021 Maximum Generation Event," (July 8, 2021) *available at* https://cdn.misoenergy.org/20210708%20MSC%20Item%2006%20Review%20of%20Max%20Gen%20Event%20-%20June%2010567565.pdf

13. Since 2022, MISO has been operating near the level of minimum reserve margin requirements.[3] This means that there is little to no excess capacity in the grid.

14. In 2023, both the MISO and SPP grid operators issued warnings about the adequacy of generation resources to meet peak demand situations.[4]

15. National organizations charged with monitoring the nation's regional power grids are reporting the same thing. The North American Electric Reliability Corporation (NERC)'s 2023 Long-Term Reliability Assessment, identified MISO as one of the two regions in the country most at risk of capacity shortfalls due to the retirement of thermal resources with inadequate reliable generation coming online to replace them.[5]

16. As soon as 2028, the MISO grid is projected to have capacity shortfalls even during normal weather. And much of the rest of the country is projected to have capacity shortfalls during severe weather events, when it is needed the most (and when renewable energy is at its least reliable). These are not historically normal projections and are a significant source of concern. And that is without this Final Rule and other federal rules forcing even more reliable, dispatchable, fossil fuel generation sources to retire.

17. A graphic from NERC's 2023 Long-Term Reliability Assessment illustrates the gravity of current projections for our national power grids.[6] Areas in red are not projected to have sufficient capacity during normal weather events. As described above, MISO, which

[3] Midcontinent Independent System Operator, "MISO'S Response to the Reliability Imperative," at 6 (Feb. 2024), *available at* https://cdn.misoenergy.org/2024%20Reliability%20Imperative%20report%20Feb.%2021%20Final504018.pdf?v=20240221104216.
[4] MATS Study at 9.
[5] North American Electric Reliability Corporation, "2023 Long-Term Reliability Assessment," (Dec. 2023), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2023.pdf.
[6] North American Electric Reliability Corporation, "2023 Long-Term Reliability Assessment," Dec. 2023, *available at* https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2023.pdf.

includes much of North Dakota, is in red. Areas in orange are not projected to have sufficient capacity in severe weather events.

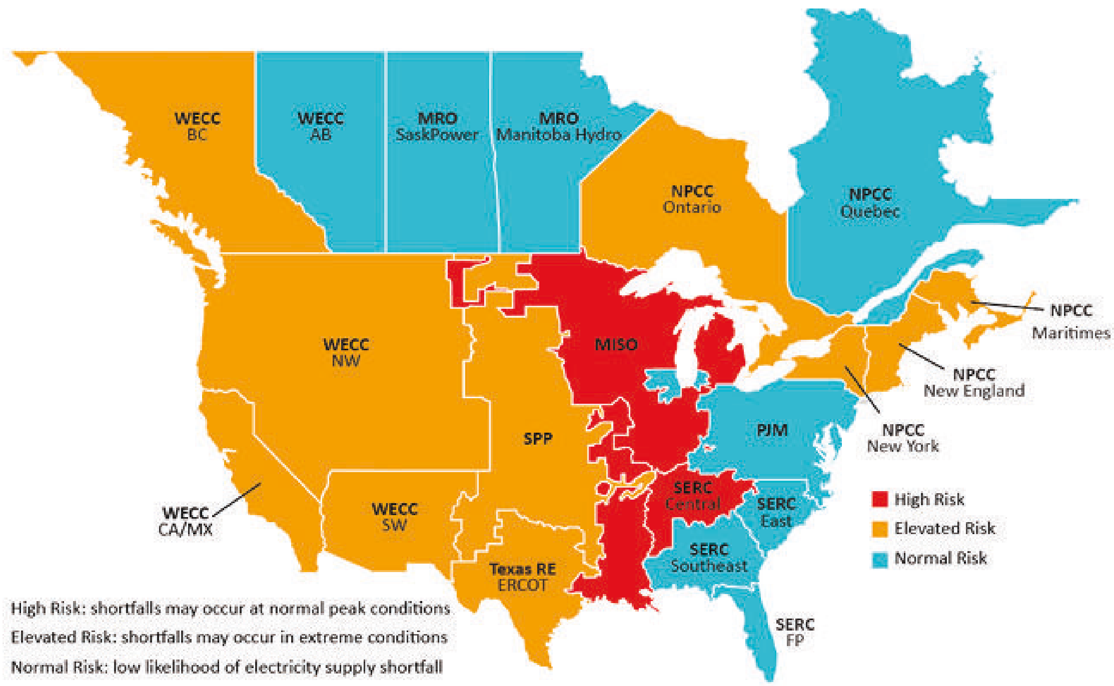


Figure 1: Risk Area Summary 2024–2028[8]

18. On February 26, 2024, MISO released "MISO's Response to the Reliability Imperative," a report that addresses the disturbing outlook for electric reliability in its footprint. The main reasons for this warning are the pace of premature retirements of dispatchable fossil generation and the resulting loss of accredited capacity and reliable energy production sources.[7] In that report, MISO states that "[w]idespread retirements of dispatchable resources, lower reserve margins, more frequent and severe weather events and increased reliance on weather-dependent renewables and emergency-only resources have altered the

[7] Midcontinent Independent System Operator, "MISO'S Response to the Reliability Imperative" (Feb. 2024), https://cdn.misoenergy.org/2024%20Reliability%20Imperative%20report%20Feb.%2021%20Final504018.pdf?v=20240221104216.

region's historic risk profile, creating risks in non-summer months that rarely posed challenges in the past."

19. That February 2024 Report from MISO contains a section titled, "EPA Regulations Could Accelerate Retirements of Dispatchable Resources," which states:

> While MISO is fuel- and technology-neutral, MISO does have a responsibility to inform state and federal regulations that could jeopardize electric reliability. *In the view of MISO, several other grid operators, and numerous utilities and states, the U.S. Environmental Protection Agency (EPA) has issued a number of regulations that could threaten reliability in the MISO region and beyond*.

20. If the Final Rule forces even more coal generation sources to shut down, there can be little doubt that it will significantly impact grid reliability and the provision of reliable electricity to the people of North Dakota and surrounding regions.

21. Even if the Final Rule does not cause plants do not shut down, implementation of the Rule's low emissions standards will necessitate operational modifications within lignite power plants. Such operational changes can compromise the inherent flexibility of lignite power plants to respond effectively to fluctuating load conditions and grid demands. The need for continuous operation of emission control systems, coupled with potential limitations in responsiveness, may impede the plant's ability to ramp up or down quickly in response to changes in electricity demand or supply. Consequently, the reliability of lignite power plants to maintain grid stability and meet grid operator requirements may be compromised, raising concerns about their ability to ensure consistent and secure electricity supply.

Potential Impact of the MATS Rule to the MISO Grid and North Dakota

22. Due to its very serious concerns about the impact the MATS Rule will have on power grid reliability for the people of North Dakota, NDTA engaged the Center of the American Experiment to model the reliability and cost impacts of the Rule in the MISO subregions

as it relates to eliminating the subcategory for lignite-fired power plants. That report is available at: https://www.ndic.nd.gov/sites/www/files/documents/Transmission-Authority/Publications/MATS_Analysis_Report.pdf ("NDTA MATS Study").

23. The NDTA MATS Study applied EPA's own capacity factor assumptions to the projected future demand growth for electricity in the MISO region, but also accounted for seasonality and timing of generation and demand based on historical use in the MISO region. *See* NDTA MATS Study at 49-50, 58-59.

24. After applying EPA's own capacity factor assumptions to projected future demand, and accounting for seasonality and timing of generation and demand, the NDTA MATS Study concluded that if lignite-fired facilities in North Dakota that serve the MISO market are forced to retire in the near future as a result of the Rule (or otherwise), it will increase the severity of future projected capacity shortfalls in the MISO region, resulting in economic damages from the ensuing blackouts ranging from $29 million to $1.05 billion over the next decade, and imposing replacement generation costs that will be passed onto ratepayers of approximately $1.9 billion to $3.8 billion. *See* NDTA MATS Study at 1, 31-32, 48.

25. Moreover, NDTA's MATS Study notes that in exchange for those projected capacity shortfalls in the MISO Region, the Final Rule will not provide any meaningful or quantifiable benefit to public health or the environment from the reductions in mercury and other air toxins that are mandated by the Rule. EPA acknowledges those levels of emission are already well below any level that would meaningfully affect public health. Indeed, as the Study notes, there is substantially more mercury emitted annually from the cremation of people with dental fillings than is emitted from all coal-fired power plants in the U.S. combined. EPA's decision to risk the reliability of our nation's power grids by imposing

a Final Rule that will not provide any meaningful public health benefit should be a cause for concern. *See* NDTA MATS Study at 16-18.

26. In summary, the long-term reliability of the power grids serving North Dakota and the surrounding regions are already in a precarious position, with demand projected to exceed supply for significant amounts of time, even under normal weather conditions. And the reason is not a mystery. Reliable, dispatchable generation sources are being pushed into premature retirement before replacement sources are projected to be online with sufficient capacity to meet demand projections. A reliable power grid is important for meeting the basic needs of modern society, therefore alarm bells should be going off. Grid reliability is vital for ensuring continuous access to essential services, such as food production and military operations. Dispatchable, reliable generation forms the backbone of grid stability, enabling the balancing of supply and demand fluctuations. Now is not the time to be forcing even more dispatchable sources onto retirement tracks for a Final Rule that will not even create any meaningful or quantifiable public health benefit.

Executed in Bismarck, North Dakota, on May 25, 2024.

Claire Vigesaa

Claire Vigesaa
Executive Director
North Dakota Transmission Authority

IN THE UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

STATE OF NORTH DAKOTA, STATE OF WEST VIRGINIA, STATE OF ALASKA, STATE OF ARKANSAS, STATE OF GEORGIA, STATE OF IDAHO, STATE OF INDIANA, STATE OF IOWA, STATE OF KANSAS, COMMONWEALTH OF KENTUCKY, STATE OF LOUISIANA, STATE OF MISSISSIPPI, STATE OF MISSOURI, STATE OF MONTANA, STATE OF NEBRASKA, STATE OF OKLAHOMA, STATE OF SOUTH CAROLINA, STATE OF SOUTH DAKOTA, STATE OF TENNESSEE, STATE OF TEXAS, STATE OF UTAH, COMMONWEALTH OF VIRGINIA, AND STATE OF WYOMING, *Petitioners*, v. U.S. ENVIRONMENTAL PROTECTION AGENCY, *Respondent*.	Case No. 24-1119

DECLARATION OF DOYLE WEBB
IN SUPPORT OF PETITIONERS' MOTION TO STAY FINAL RULE

I, Doyle Webb, hereby declare pursuant to 28 U.S.C. § 1746 and state under penalty of perjury that the following is true and correct to the best of my knowledge and is based on my personal knowledge or information available to me in the performance of my official duties:

1. I am the Chairman of the Arkansas State Public Service Commission (Commission or PSC). I have held this position since January 17, 2023. I am over the age of 18 and am competent to testify concerning the matters in this declaration based on my personal knowledge, my experience with the PSC, and information provided to me by PSC personnel.

2. The PSC is responsible for regulating the service and rates of utilities, including electric and gas utilities serving retail customers in Arkansas. As Chairman of the PSC, I am charged with the responsibility for appraising and balancing the interests of current and future utility service customers, the general interests of the State economy and the interests of the utilities subject to Commission jurisdiction in its deliberations and decisions. The Commission actively participates in the governance of two Regional Transmission Organizations: the Midcontinent Independent System Operator (MISO), through the Organization of MISO States, and Southwest Power Pool (SPP), through the Regional State Committee.

3. I am submitting this declaration in support of Petitioners' Motion to Stay the Final Rule, published by the U.S. Environmental Protection Agency (EPA) on May 7, 2024, entitled "National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review," 89 Fed. Reg. 38508 (Final Rule).

4. I am aware that the EPA published the Final Rule following EPA's proposed Rule issued on April 24, 2023. See 89 Fed. Reg. 24854.

5. The Final Rule will negatively impact Arkansas, its ratepayers, and its utilities that own and operate generation facilities.

6. The Final Rule will make electricity less reliable in Arkansas and throughout the grid by forcing the retirement of base load resources, only serving to exacerbate the threat of brownouts and blackouts, as well as long-term negative cost impacts.

7. The Federal Energy Regulatory Commission, the North American Electric Reliability Corporation (NERC), and entities charged with overseeing the reliability of our power grids have warned about the long-term reliability of our nation's power grids. NERC recently stated that the bulk power system has reached an "inflection point" in which the risk profile to customers is steadily deteriorating due to the retirement of valuable generation resources outpacing the addition of new dispatchable generation.[1]

8. In its *2023 Long Term Reliability Assessment*, NERC identified that the SPP region will be at an "elevated risk" of shortfall in extreme conditions.

9. NERC has also identified risk in MISO, projecting a "high risk" level indicating insufficient resource adequacy for the majority of Arkansas.[2] This indicates that the electricity supply for these areas is more likely to be insufficient in the forecast period and more firm resources are needed. While MISO has seen an upward trend in installed capacity, accredited capacity to meet system needs is moving in the opposite direction. MISO's recent accreditation reforms around direct loss of load indicate that this trend is likely to worsen.[3]

10. MISO released the following statement:

---

[1] The Reliability and Resiliency of Electric Service in the United States in Light of Recent Reliability Assessments and Alerts: Hearing Before the Committee on Energy and Natural Resources (June 1, 2023) (Statement of James B. Robb, North American Electric Reliability Corporation).

[2] *Id.*

[3] Midcontinent Independent System Operator (MISO), *Managing Reliability Risk in the MISO Footprint* (June 16, 2022), *available at* https://cdn.misoenergy.org/20220616%20Board%20of%20Directors%20Item%2008a%20Reliability%20Imperative625168.pdf.

> There are urgent and complex challenges to electric system reliability in the MISO region and elsewhere. This is not just MISO's view; it is a well-documented conclusion throughout the electric industry. …
>
> Many dispatchable resources that provide critical reliability attributes are retiring prematurely due to environmental regulations and clean-energy policies. …
>
> The new weather-dependent resources that are being built, such as wind and solar, do not provide the same critical reliability attributes as the conventional dispatchable coal and natural gas resources that are being retired. While emerging technologies such as long duration battery storage, small modular reactors and hydrogen systems may someday offer solutions to this issue, they are not yet viable at grid scale[4]

11. In summary, the Final Rule will likely have lasting negative impacts. Unless a stay is immediately granted, the Final Rule will impose significant and irreparable harm on Arkansas and its citizens.

I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge. Executed in Little Rock, Arkansas, on May 22, 2024.

Doyle Webb

Doyle Webb
Chairman
Arkansas Public Service Commission

---

[4] Midcontinent Independent System Operator, "MISO's Response to the Reliability Imperative," at 2 (Feb. 2024), *available at* https://cdn.misoenergy.org/2024%20Reliability%20Imperative%20report%20Feb.%2021%20Final504018.pdf?v=20240221104216.

DECLARATION OF JASON BOHRER

I, Jason Bohrer, declare as follows:

1. I am over eighteen years of age, suffer from no disability that would preclude me from giving this declaration, and make this declaration based upon personal knowledge or information available to me in the performance of my professional duties.

2. I am President and Chief Executive Officer of the Lignite Energy Council (LEC).

3. I have been employed by the LEC for 11 years and held my current title for that entire time. My responsibilities include directing and coordinating the policy work and research and development priorities of the LEC.

4. The LEC is a trade association that represents various lignite mines, lignite-fired power plants and conversion facilities, as well as the businesses that contribute goods and services to the industry. Its members produce electricity and also gasify lignite coal, which is then turned into synthetic natural gas and other valuable byproducts.

5. LEC members provide electricity to two Regional Transmission Organizations: the Midcontinent Independent Systems Operator and the Southwest Power Pool.

6. I am providing this declaration in support of the motion to stay the rule promulgated by the U.S. Environmental Protection Agency ("EPA") entitled *National*

Emission Standards for Hazardous Air Pollutants: Coal-and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review, 89 Fed. Reg. 38,508 (May 7, 2024) ("MATS RTR").

7. The MATS RTR threatens the viability of North Dakota's lignite-fired power plants and coal mines. The MATS RTR also endangers the reliability and resilience of the power grids in North Dakota and the surrounding regions.

8. LEC members have extensive experience in operating electric generating units (EGUs) powered by lignite coal while using a variety of emission control technologies.

9. North Dakota contains the world's largest deposit of lignite coal. Lignite coal is a geologically young form of coal and lacks the homogeneity found in older types of coal.

10. In North Dakota, lignite coal is mined adjacent to the EGUs and conversion facilities where it is used in a "mine-to-mouth" operation. Each EGU contracts with an individual lignite mine for its supply of lignite, and these EGUs have been geographically sited based on the availability of lignite coal. Neither market economics nor coal transportation logistics allow for fuel switching or coal blending. Should an associated lignite EGU close, the mine providing coal for it would have no reasonable or viable market alternative.

11. The total number of EGU employees in North Dakota is 7,725, and the total number of mining jobs is 3,250. This ratio suggests that for each employee at a mine there are two employees at a power plant.

12. Emission control solutions are not interchangeable and are crafted on an EGU-by-EGU basis due to the differences in coal composition, power plant technology and operational needs at each facility.

13. Particularly for lignite-firing EGUs, the variability in chemical composition of lignite coal, along with mine-to-mouth operations, requires that EGUs maintain an emission control compliance margin that accounts for variability in coal composition and required operational conditions.

14. The lignite subcategory created by the EPA in the 2012 MATS rule reflected the reality that the chemical makeup and characteristics of lignite not only cause different emissions profiles than bituminous or sub-bituminous coals, but also reflect the lower homogeneity of lignite coal compared to other types of coal.

15. The lignite subcategory therefore reflected basic chemical truths, such as the mechanism by which the higher sulfur content of lignite reduces the effectiveness of sorbent mercury reduction solutions and the interplay between the formation of SO3 and potential mercury reduction technologies.

16. LEC is not currently aware of any verified or demonstrated technology that will consistently allow all of North Dakota's lignite-firing EGUs to comply with the MATS RTR's newly lowered Hg requirement of 1.2 lb/TBtu.

17. Illustrating that point, testing performed by LEC member Minnkota Power Cooperative verified that the increased utilization of sorbents, even at significantly elevated levels, would not result in consistent compliance with the newly reduced Hg limit.

The new limit will cause immediate and irreparable harm to LEC Members.

18. LEC's members are actively trying to determine if they will be able to comply with the MATS RTR's reduced emission requirements and still remain commercially viable. Testing alone to accurately quantify the requirements specific to each unique EGU is estimated at more than $1,000,000.00 per unit.

19. Even if such further testing indicated the new emission limitations could be met (and it is not currently clear that they could be), the construction costs necessary to update or replace existing technologies and optimize operation would be expensive and time consuming.

20. New expenses would be added to those one-time construction expenditures (estimated at a minimum of $5,000,000.00 by Minnkota Power Cooperative for a single facility to between $55,000,000 and $500,000,000 for Basin Electric Cooperatives' generating fleet) by requiring additional sorbents or other

control materials. These new expenses would continue in perpetuity along with increased operating costs.

21. Each EGU in North Dakota is unique, but they share in the difficulty of establishing the feasibility of a path to compliance, and, if one is achievable, the expenses incurred in implementation, as well as the continual ongoing costs. For example, a baghouse is estimated to cost $282,715 per fPM ton removed while an ESP retrofit is estimated at $67,262 per fPM ton removed. Operators will be forced to pass along those costs to ratepayers or other end users to continue to operate.

22. Moreover, should feasibility testing indicate compliance is possible, the substantial modifications required by the MATS RTR would need to be implemented immediately.

23. For example, electrostatic precipitator upgrades carry a three-year timeline from start of construction to implementation. For the EPA's assessment to be accurate that no facilities will close due to the MATS RTR, at least 26 impacted EGUs in the country would be competing for the 4 vendors capable of performing the work. And based on historical performance, it is unlikely the four contractors could perform the work needed for all 26 plants in that 3-year period.

24. The alternative to compliance is to shut down or operate at such a reduced level that end of life will occur prematurely for the EGU. For every two jobs

lost at a power plant due to premature shut down, a worker in a lignite mine who will also lose their job.

The MATS RTR Rule will harm North Dakotans

25. The elimination of the lignite subcategory will impact North Dakota and North Dakotans in multiple ways. Lignite provides most of the electricity consumed in North Dakota, and it provides the backbone of reliability and resilience.

26. Should testing indicate compliance with the MATS RTR's new emission limits is possible for every EGU in North Dakota, the implementation of new control technologies at each EGU would require multiple EGUs be taken offline for extended periods of time, concentrating the danger of an unstable, unreliable grid on North Dakota and its residents.

27. As a recent study commissioned by the North Dakota Transmission Authority confirmed, the power grids serving the people of North Dakota are already operating on dangerously thin margins of dispatchable power. Available at https://www.ndic.nd.gov/sites/www/files/documents/Transmission-Authority/Publications/MATS_Analysis_Report.pdf. Consequently, even if Noth Dakota plants are capable of complying with the MATS RTR's new standards (which, as noted above, remains entirely uncertain), complying with the Rule would require taking multiple units offline for an extended duration to make necessary upgrades, removing load from power grids that are not projected to have capacity to spare.

28. Winters in North Dakota require consistently available power for homes, hospitals and businesses to provide care and services for families. Previous blackouts in other parts of the country associated with Winter Storm Uri have demonstrated that death and health impacts can follow blackouts even in relatively mild weather.

29. Consequently, the MATS RTR will impose significant regulatory burdens and cost on coal-fired EGUs in North Dakota and create serious risks to the health and welfare of people in the region.

30. I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge.

Executed this 3rd day of June 2024.

Jason Bohrer

Jason Bohrer
President and Chief Executive Officer
Lignite Energy Council

Kristina Tridico
Deputy General Counsel -Regulatory
Direct Dial: 317-618-0151
Email: ktridico@misoenergy.org

April 10, 2023

VIA ELECTRONIC Submission and Email

Attn: Michelle Lloyd
Office of Resource Conservation and Recovery, Materials Recovery and Waste Management Division, Environmental Protection Agency,
1200 Pennsylvania Avenue NW, MC: 5304T, Washington, DC 20460
Lloyd.Michelle@epa.gov

Re: Comments from the Midcontinent Independent System Operator, Inc. (MISO) Regarding the United States Environmental Protection Agency's Request for Comment re Docket ID Nos. EPA-HQ-OLEM-2021-0283, EPA-HQ-OLEM-2021-0282, EPA-HQ-OLEM-2021-0280.

The Midcontinent Independent System Operator ("MISO") offers these comments on the proposal by the United States Environmental Protection Agency ("EPA") to deny applications by DTE Electric Company's ("DTE") 1.3-GW Belle River[1] and 3.3-GW Monroe Power[2] Plants in Michigan and Rainbow Energy Center, LLC's ("Rainbow") 1.2-GW Coal Creek Station in North Dakota[3] (collectively the "Plants") for an alternate liner demonstration (ALD) to allow coal combustion residuals ("CCR") surface impoundments to continue to receive CCR and non-CCR waste streams after the current April 11, 2021, deadline to cease receipt of wastes. EPA has proposed to deny these requests[4] and require the Plants to: 1) submit an application for a site-specific alternative deadline to initiation closure of its CCR surface impoundment(s) or 2) cease receipt of waste no later than 135 days after EPA issues its final determination on the proposed denial of the ALD application (or a later date as EPA determines is necessary to address grid reliability).[5] EPA has requested comment on its denials of the Plants' alternate liner demonstrations and its proposed date for the Plants to cease receipt of waste. *See* EPA-HQ-OLEM-2021-0280-0001 at p. 2; EPA-HQ-OLEM-2021-0282-0001 at p. 2; EPA-HQ-OLEM-

[1] *See https://www.regulations.gov/document/EPA-HQ-OLEM-2021-0282-0001.*
[2] *See https://www.regulations.gov/document/EPA-HQ-OLEM-2021-0283-0001.*
[3] *See https://www.regulations.gov/document/EPA-HQ-OLEM-2021-0280-0001.*
[4] The bases for EPA's proposed decisions are explained in the following memos and proposed determinations: 1) Proposed Denial of the CCR Part B Alternate Liner Demonstration Application Great River Energy Coal Creek Station, Upstream Raise 91, Underwood, North Dakota, *EPA-HQ-OLEM-2021-0280-0001 at p. 2*; Proposed Denial of the CCR Part B Alternate Liner Demonstration Application, DTE Electric Belle River Power Plant Bottom Ash Ponds and Diversion Basin, China Township, Michigan , *EPA-HQ-OLEM-2021-0282-0001 at p. 2*; Proposed Denial of the CCR Part B Alternate Liner Demonstration Application, DTE Energy Monroe, Fly Ash Basin, Monroe, Michigan, *EPA-HQ-OLEM-2021-0283-0001 at p. 2*.
[5] *See* EPA-HQ-OLEM-2021-0280-0001 at p. 2; EPA-HQ-OLEM-2021-0282-0001 at p. 2; EPA-HQ-OLEM-2021-0283-0001 at p. 2.

2021-0283-0001 at p. 2. The comment period on these proposals extends to April 10, 2023. *See* EPA-HQ-OLEM-2021-0280-0014; EPA-HQ-OLEM-2021-0282-0013; EPA-HQ-OLEM-2021-0283-0011. MISO's comments will focus on issues surrounding the potential date for cessation of operations at these facilities, including receipt of wastes, relevant to the electrical grid and resource availability.

By way of background, MISO [6] delivers power from the high-voltage transmission grid to local distribution utilities, which then are responsible for delivery to end-use customers. MISO is authorized by the Federal Energy Regulatory Commission ("FERC") to exercise "functional control" over the high voltage transmission system and otherwise administer the bulk electric system in its region. One of MISO's critical functions is to facilitate and maintain the reliable delivery of electricity. MISO acknowledges and appreciates the role that EPA and other governmental agencies play in addressing environmental matters, including grid reliability issues.

- **EPA MUST CONSIDER RESOURCE ADEQUACY AND GRID RELIABILITY ISSUES IN ITS DECISIONS REGARDING ANY DATE FOR CESSATION OF WASTE RECEIPT AT THE PLANTS.**

The electric grid is undergoing significant fleet changes that creates an immediate need for stakeholders to work together to address and maintain electric reliability. MISO's studies indicate that its region needs a certain level of dispatchable and flexible resources to reliably manage the transition to a decarbonized energy future. MISO faces increasing challenges to system reliability and the ability to commit sufficient resources to supply electricity to customers within the Midcontinent region.[7] Even with the recognized growth of alternative and renewable energy

[6] MISO is an independent, not-for-profit, member-based organization responsible for managing the power grid across 15 U.S. states and the Canadian province of Manitoba. MISO is both fuel- and technology-neutral. Today, 45 million people depend on MISO to coordinate the generation and transmission of the right amount of electricity every minute of every day. MISO is committed to delivering electricity reliably, dependably and cost effectively. In addition to managing the power grid within its region, MISO administers the buying and selling of electricity at the wholesale level, and partners with members and stakeholders to plan the grid of the future.

[7] Studies conducted by MISO and other Regional Transmission Organizations (RTOs) have verified that their transmission systems are at their capacity and there are financial and other impairments currently impacting the ability to address this lack of capacity issue. MISO's Long Range Transmission Plan details interconnection issues[7] and its Planning Resource Auction (PRA) process shows strains in the availability of sufficient generating capacity to meet the region's needs. See MISO's 2022/2023 PRA resulted in a capacity shortfall for the MISO North/Central Regions despite the fact that MISO was able to import over 3,000 MW from neighboring regions. *See, e.g.*, MISO 2022/2023 Planning Resource Auction (PRA) Results, April 14, 2022, *available at* https://cdn.misoenergy.org/2022%20PRA%20Results624053.pdf. *See also* MISO 2022/2023 Planning Resource Auction (PRA) Results, Revised May 3, 2022, *available at* https://cdn.misoenergy.org/20220420%20RASC%20Item%2004b%20PRA%20Results%20Supplemental624128.pdf. See MISO 2022 Regional Resource Assessment (Nov. 2022), *available at* https://cdn.misoenergy.org/2022%20Regional%20Resource%20Assessment%20Report627163.pdf noting an overall decline in accredited capacity in 2022 and near term capacity risk as well as increased complexity of reliability operating and planning the electric system due to changes in generator sources); MISO's Response to the Reliability Imperative (Jan. 2023), available at https://cdn.misoenergy.org/MISO%20Response%20to%20the%20Reliability%20Imperative504018.pdf (addressing the shared responsibility of shareholders to address the urgent and complex challenges to electric system reliability and noting that the MISO region has been inching ever closer to experiencing a shortfall in electricity-generating

sources, MISO continues to be concerned about the looming shortfall of generation needed to ensure grid reliability in the region. Within the MISO region, the retirement of generation plants is occurring far faster than new energy sources with equivalent attributes, whatever the fuel source, can be developed, constructed, and brought online. While MISO is both fuel- and technology-neutral, it needs to preserve the best options to provide these needed resource capabilities and attributes to bridge the gap between retirements and replacement capabilities and attributes.

MISO has concerns as to grid reliability and resource adequacy. Resource adequacy, in general terms, is achieved when the accredited megawatt capacity of the generators in a particular region meets or exceeds the forecasted load, plus reserves, for that region. MISO is experiencing a trending decline in reserve margin and fewer always-on "baseload" resources, which is largely the result of the retirement of significant amounts of dispatchable generation and the retirement of thermal units. Different types of resources are accredited, or count, for different amounts capacity depending on how reliable they are to be able to generate at the time they are needed. The traditional dispatchable generators like Coal, impacted by the CCR rules, tend to have much higher accredited capacity than the replacement capacity that has been brought online in recent years. Replacement of retiring generation with new, mostly intermittent facilities that are not installed at the same time or valued at the same output presents its own risks. Moreover, new capacity from these resources (*i.e.,* non-thermal) is not always available to provide energy during times of need. For instance, MISO has previously expressed concern to EPA regarding issues related to withdrawal of service by the Dalman, Erickson, Meramec, Ottumwa, and Sioux power plants and potential impacts from the loss of generation from these five generators.[8] In particular, MISO commented that "[b]ased on the most currently available information . . . there is very little excess generating capacity (or none at all) to cover demand for electricity, plus the required reserve margin, in the immediate future."[9] It takes time to obtain the required regulatory approvals to construct new generation and especially any needed transmission facilities to connect that generation to the grid. In the interim, resource adequacy must be maintained, and reliability standards met during this period. Accordingly, the future of the electric grid and associated electric markets depend upon resource availability, flexibility, and visibility.

While resource adequacy is generally the responsibility of the state regulatory authorities within the Midcontinent region, MISO is in a unique position as the grid operator to inform state and environmental regulators on the regional impact of actions on grid reliability and customer impacts. Given the changes to the generating fleet, and the potential shortfalls in generating capacity, it is imperative that EPA consider the need for reliable generating resources for the regional reliability value provided to the region's customers. Given the existing regional supply

---

capacity due to widespread retirements of conventional resources, not enough replacement capacity coming online, and other factors). FERC also notes backlogs of more than three years in the interconnection queue. *See* FERC Proposes Interconnection Reforms to Address Queue Backlogs, *available at*, https://www.ferc.gov/news-events/news/ferc-proposes-interconnection-reforms-address-queue-backlogs (noting significant current backlogs in the interconnection queues of more than three years).

[8] *See* Comments of Midcontinent Independent System Operator (MISO) related to EPA-HQ-OLEM-2021-0588, EPA-HQ-OLEM-2021-0589, EPA-HQ-OLEM-2021-0592, EPA-HQ-OLEM-2021-0593, and EPA-HQ-OLEM-2021-0594, *available at* https://www.regulations.gov/comment/EPA-HQ-OLEM-2021-0588-0010.
[9] *Id.* at p. 6, *available at* https://www.regulations.gov/comment/EPA-HQ-OLEM-2021-0588-0010

situation, resources need to remain online and available to provide capacity and transmission grid stability to meet the system's needs until sufficient replacement capability is brought online.

MISO would note that it has multiple facilities potentially impacted by proposed EPA denials of ALD determinations for CCR wastes. Accordingly, retirement/suspension requests as well as planned outages will require particular attention to ensure continued grid reliability and resource adequacy. The Plants at issue in this particular comment serve crucial power corridors and provide a combined 5.9 GW to the grid.

- **MISO HAS MADE MODIFICATIONS TO ITS TIMING REQUIREMENTS FOR GENERATOR SUSPENSIONS AND RETIREMENTS THAT EPA WILL NEED TO CONSIDER IN ITS DETERMINATION OF WHEN PLANTS WILL NEED TO CEASE RECEIVING WASTES AND OPERATE.**

With regard to potential timing for the Plants to cease receiving wastes and operation, EPA has requested comments on its proposed dates for the Plant to cease receipt of waste. EPA noted that the Plants would have "four months from the date of the ineligibility determination to apply for an alternative closure deadline, during which time the facility's deadline to cease receipt of waste to be tolled." *See EPA-HQ-OLEM-2021-0280-0001 at p. 52; EPA-HQ-OLEM-2021-0282-0001 at p. 51; EPA-HQ-OLEM-2021-0283-0001 at p. 46*. Should a plant be unable to submit a demonstration requesting an alternative closure deadline, EPA has proposed that the plant cease receipt of waste within 135 days of the date of the Agency's final decision (*i.e.*, the date on which the decision is signed) as this would time period would provide the same amount of time that would have been available to the Plants had EPA issued a denial immediately upon receipt of their applications (i.e., from November 30, 2020, when EPA received the submission, to April 11, 2021, the regulatory deadline to cease receipt of waste). *See EPA-HQ-OLEM-2021-0280-0001 at pp. 52-53; EPA-HQ-OLEM-2021-0282-0001 at pp. 51-53; EPA-HQ-OLEM-2021-0283-0001 at pp. 46-47.* EPA has proposed that it may authorize additional time for continued use of the impoundments to the extent necessary to address demonstrated grid reliability issues, provided that a planned outage request is submitted to MISO "within 15 days of the date of EPA's final decision" and "a MISO determination disapproving the planned outage and the formal reliability assessment upon which it is based" is provided to EPA within 10 days of receipt by the submitting party. *See EPA-HQ-OLEM-2021-0280-0001 at pp. 53; EPA-HQ-OLEM-2021-0282-0001 at pp. 52; EPA-HQ-OLEM-2021-0283-0001 at pp. 46-47.*

EPA has stated that it is sensitive to the importance of maintaining enough electricity generating capacity to meet the Midcontinent region's energy needs, including meeting specific, localized issues. *See EPA-HQ-OLEM-2021-0280-0001 at p. 55; EPA-HQ-OLEM-2021-0282-0001 at p. 54; EPA-HQ-OLEM-2021-0283-0001 at p. 48.* EPA is proposing to rely on MISO's procedures for reviewing planned maintenance outage and similar requests to determine the appropriate date for the Plants to cease taking waste. *See EPA-HQ-OLEM-2021-0280-0001 at pp. 56-57; EPA-HQ-OLEM-2021-0282-0001 at pp. 55-56; EPA-HQ-OLEM-2021-0283-0001 at pp. 49-50.* EPA further stated that in MISO's region "power plants are normally required to submit a request at 26 weeks in advance of a planned outage to allow MISO to evaluate whether the resource is needed to maintain grid reliability, among other scheduling considerations" and that MISO would be able to "to provide an initial assessment of reliability within 135 days." *See EPA-HQ-*

Minnkota Power COOPERATIVE
A Touchstone Energy® Cooperative

5301 32nd Ave S
Grand Forks, ND 58201-3312

Phone 701.795.4000
www.minnkota.com

June 23, 2023

Administrator Michael S. Regan
U.S. Environmental Protection Agency
1200 Pennsylvania Avenue, NW
Washington, DC 20460

RE: Comments from Minnkota Power Cooperative, Inc. on 88 Fed. Reg. 24854 (April 24, 2023), Docket ID No. EPA–HQ–OAR–2018–0794

Dear Administrator Regan,

Minnkota Power Cooperative, Inc.(Minnkota) appreciates the opportunity to provide comments on EPA's proposed rule entitled "National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review" (the Proposed Rule). This Proposed Rule concerns the Mercury and Air Toxics Standards (the MATS Rule) under Clean Air Act (CAA) Section 112.

Minnkota is a not-for-profit electric generation and transmission cooperative headquartered in Grand Forks, North Dakota. We are comprised of 11 member-owner distribution cooperatives located in eastern North Dakota and northwestern Minnesota, and serve some 160,000 cooperative members, rate-payers. Minnkota also serves as the operating agent for the Northern Municipal Power Agency (NMPA), headquartered in Thief River Falls, MN. Since our formation in 1940, Minnkota has been committed to delivering safe, reliable, affordable and environmentally-responsible energy to its member cooperatives.

Minnkota operates the Milton R. Young Station (the Young Station), a two-unit, cyclone lignite coal-fired power plant located near the town of Center, North Dakota, that currently complies with the MATS rule. Consequently, as the operator of the Young Station, Minnkota has a strong interest in commenting on the proposed revisions in this rulemaking.

We believe EPA's decision to affirm the robust and technically sound residual risk analysis concluded in 2020 is well supported. However, our comments further address our serious concerns that the EPA (1) lacks a legal basis for this proposed rulemaking; (2) used a flawed methodology, resulting in erroneous filterable particulate matter and mercury baselines; and (3) relied upon technical conclusions that suffer from several significant technical errors. EPA must modify the

Docket ID No. EPA–HQ–OAR–2018–0794

COMMENTS OF MINNKOTA POWER COOPERATIVE ON THE NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS: COAL - AND OIL-FIRED ELECTRIC UTILITY STEAM GENERATING UNITS REVIEW OF THE RESIDUAL RISK AND TECHNOLOGY REVIEW; PROPOSED RULE
88 Fed. Reg. 24854 (April 24, 2023)
Docket ID No. EPA–HQ–OAR–2018–0794

Minnkota appreciates the opportunity to provide comments on EPA's proposed rule entitled "National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review" (the Proposed Rule).[1] This Proposed Rule concerns the Mercury and Air Toxics Standards (the MATS Rule) under Clean Air Act (CAA) Section 112. Minnkota operates the Milton R. Young Station (the Young Station) that currently complies with the MATS rule. Consequently, Minnkota has a strong interest in commenting on the proposed revisions in this rulemaking.

I. Introduction.

In June, EPA recognized dramatic air quality improvements since 1990.[2] All major air pollutants have fallen, including hazardous air pollutants (HAPs), which are the topic of this rulemaking. Concurrently, our nation is facing an energy reliability crisis. The North American Electric Reliability Corporation (NERC) recognizes the unprecedented, rapid evolution of the electricity grid due to retirements of fossil generation and renewable generation coming on-line.[3] NERC predicts electricity shortfalls in the MISO portion of the electricity grid that Minnkota serves. S&P Global reports that: "Utilities in MISO are retiring fossil capacity in exchange for investments in renewable energy resources either contracted or added to their rate base; however, those exchanges are not happening fast enough to replace all the generation coming offline."[4]

Despite air quality improvements and reliability fears, EPA presses the power sector further in the proposed rule entitled, "National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review" (the Proposed Rule).[5] The rulemaking comes at a time when fossil fuel-fired electric generating units (EGUs) are contending with significant rulemakings that will create a sizeable cumulative cost burden on the industry in a short time period, most by 2028. For example, in addition to the Proposed Rule, there currently are open comment periods on other complex proposed rules directly affecting electric cooperatives:

---

[1] 88 Fed. Reg. 24854 (Apr. 24, 2023).
[2] Our Nation's Air, June 2023, https://gispub.epa.gov/air/trendsreport/2023/documentation/AirTrends_Flyer.pdf
[3] NERC, Long-Term Reliability Assessment, December 2022 at 5, https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2022.pdf
[4] Bennett, "Outlook 2023: MISO expects net addition of 8.9 GW, may face capacity strain" S&P Global (May 3, 2023)
[5] 88 Fed. Reg. 24854 (Apr. 24, 2023).

> Nine states experienced rolling blackouts last December as the demand for electricity exceeded the available supply. Those situations will become even more frequent if EPA continues to craft rules without any apparent consideration of impacts on electric grid reliability. American families and businesses rightfully expect the lights to stay on at a price they can afford. EPA needs to recognize the impact this proposal will have on the future of reliable energy before it's too late.[6]

The reliability and the costs of this Proposed Rule should be considered as required by CAA Section 112. It is crucial for EPA to evaluate the overall regulatory context. The burden of environmental compliance on electric cooperatives and their end users is cumulatively affected by the compliance timelines of these concurrent rulemakings.

Minnkota appreciates EPA's recognition and consideration of these overarching impacts on electric cooperatives and on the nation's grid. Minnkota advocates for adjustment of the fPM emissions limit to 0.020 lb/mmBtu or greater, which would account for a compliance margin to accommodate variability in unit operation. Minnkota asks EPA to revise the mercury (Hg) analysis to correct critical errors, which is necessary to determine whether a Hg emissions limit can be consistently met by lignite units, as further discussed infra. Minnkota supports the following specific changes to the proposal:

- Correct the flawed fPM baseline to accurately account for current EGU emissions and fPM control device capabilities.
- Recognize that EGUs vary in different seasonal and operational conditions as well as on a unit-by-unit basis due to size, unit-type, fuel and climate. A compliance margin is necessary to account for these differences.
- Correct the fPM cost analysis to quantify the appropriate number of fPM upgrades and cost values, such that the cost is not underestimated.
- Consider the time frames in which certain fPM control upgrades and installations can realistically occur.
- Retain the option to stack test for fPM and non-metal HAPs.
- Reconsider the substantial Hg reductions proposed for lignite-fired units that rely on flawed technical assumptions as to the capabilities of lignite units.
- Adopt reasonable revisions or keep the current PM CEMS correlation test requirements that apply to units that elect to use PM CEMS for MATS compliance.
- Revise the IPM model to refrain from overvaluing the impacts of the Inflation Reduction Act of 2022 (IRA) as the basis for the regulatory impacts analysis for this Proposed Rule.

---

[6] Matheson, Electric Co-ops: EPA's Power Plant Proposal Would Further Jeopardize Reliability, May 11, 2023, https://www.electric.coop/electric-co-ops-epas-power-plant-proposal-would-further-jeopardize-reliability (discussing Section 111 greenhouse gas regulations as the latest problematic EPA rule to jeopardize reliability).

January 15, 2016

VIA ELECTRONIC MAIL TO: a-and-r-docket@epa.gov

Dr. Nick Hudson
Energy Strategies Group, Sector Policies &
Programs Division (D243-01)
U.S. Environmental Protection Agency
Research Triangle Park, NC 27711

Attention: Docket ID No. EPA–HQ–OAR–2009–0234

Re: Comments of the National Mining Association on Supplemental Finding That It Is Appropriate and Necessary To Regulate Hazardous Air Pollutants From Coal- and Oil-Fired Electric Utility Steam Generating Units, 80 Fed. Reg. 75,025 (Dec. 1, 2015)

Dear Dr. Hudson:

The National Mining Association (NMA)[1] submits these comments in response to the proposed supplemental finding that it is appropriate and necessary to regulate hazardous air pollutants (HAPs) from coal and oil-fired electric utility steam generating units (EGUs), 80 Fed. Reg. 75,025 (Dec. 1, 2015). In addition to submitting these comments NMA incorporates by reference the comments of the Utility Air Regulatory Group of which NMA is a member.

NMA urges EPA to rescind and re-propose its "appropriate and necessary" finding for electric generating units. EPA's proposed finding is based on an arbitrarily limited view of the information the agency should examine in assessing the costs and benefits of regulation. EPA seems more interested in quickly reaffirming the flawed appropriate and necessary finding it made when it issued the MATS rule rather than conducting the type of searching analysis the Supreme Court called for in *Michigan v. EPA*, 135 S. Ct. 2699 (2015), where the Court directed the agency to "consider cost-including, and most importantly, cost of compliance **before** deciding whether regulation is appropriate and necessary." (Emphasis added.) Despite this rebuke from the Court,

[1] NMA's membership includes the producers, transporters and consumers of coal. Our member companies mines over 75 percent of the coal produced annually from operations located in 26 states. Most of the coal produced by NMA members is used by coal-fired EGUs subject to this rulemaking.

National Mining Association 101 Constitution Avenue, NW | Suite 500 East | Washington, DC 20001 | (202) 463-2600

our analysis of the Supplemental Finding demonstrates that it, like the agency's prior determination, is wrong in reaching the conclusion that it is appropriate and necessary to regulate HAP emissions from EGUs.[2]

1. EPA has completely failed to consider the effect of its rule on coal.

Four years after MATS was issued, with the damage the rule caused in the coal industry all but complete, EPA maintains its preposterous view reached in the MATS Regulatory Impact Analysis (RIA) that the rule will have little effect on coal. EPA has no new analysis to support this assertion as no such analysis can be constructed. It simply proposes to limit its consideration of costs to the information it included in the RIA, including the RIA forecast that the rule would result in the retirement of less than 5 GW of coal capacity.[3] By limiting its cost consideration in this fashion, the agency believes it can erase the actual experience of the last four years and the hardship the agency has wrought on our nation's coal communities and ratepayers who were previously the beneficiaries of affordable, reliable coal-based electricity.

As numerous commenters, including NMA, told EPA during the MATS rulemaking, the rule would cause a wave of coal unit retirements. Unfortunately, events have confirmed the accuracy of these forecasts and disproved EPA's. Between 2012 when the rule went into effect and 2016 when the rule's compliance period ends, almost 60 GW of coal capacity will have retired, including units that have already retired or, for 2016, have announced their retirement.

Coal-Fired Generating Unit Retirements by Year – Actual and Announced (MW)

Year	Annual	Cumulative
2012	12,601	12,601
2013	8,220	20,821
2014	5,568	26,389
2015	20,728	47,116
2016	12,065	59,181

Source: Energy Ventures Analysis

According to statements made by the utilities announcing the retirements, virtually all of these closures are either fully or partially attributable to MATS and other EPA regulations.[4]

[2] To ensure a complete record here, NMA attaches and resubmits its MATS comments.
[3] EPA Regulatory Impact Analysis for the Final Mercury and Air Toxics Standards, page 3-17.
[4] See attached compilation from the American Coalition of Clean Coal Electricity.

AMERICAN COALITION FOR CLEAN COAL ELECTRICITY

COAL UNIT RETIREMENTS[1]

As of December 30, 2015

- Since 2010, utilities have announced the retirement of a very large number of coal-fired electric generating units.[2] In addition to these retirements, some coal units are converting to natural gas, and a small number are converting to biomass or another fuel. Most of these retirements and conversions have been attributed to EPA policies, although other factors may play a role too.[3]

- Table 1 lists 37 states with coal retirements and conversions that have been attributed to EPA policies. These retirements and conversions total 410 units and represent nearly 67,000 megawatts (MW) of electric generating capacity. Approximately 12,000 MW (one-fifth of the total) are converting to natural gas, biomass, or another fuel. By the end of 2016, 51,481 MW will retire or convert due to EPA policies.

- Table 2 lists all announced coal retirements and conversions, regardless of cause, through 2030. (Table 2 includes the units in Table 1 plus additional retirements and conversions that have not been attributed to EPA policies.) Table 2 shows that 499 units — totaling over 81,000 MW — are slated for retirement or conversion. These units are located in 42 states and represent 26% of the U.S. coal fleet that existed in 2010. Approximately 14,000 MW (slightly less than one-fifth of the total) are converting to natural gas, biomass, or another fuel.

- By the end of 2015, approximately 50,000 MW will have retired or converted. Between 2016 and 2019, an additional 22,000 MW are expected to retire or convert.[4]

---

[1] This list of retirements and conversions is based primarily on public announcements by the owners of the coal units. We also use other information sources that are highly reliable. These retirements and conversions are not based on modeling projections.
[2] In 2010, according to EIA, the U.S. coal fleet was comprised of 1,396 electric generating units at 580 power plants that represented a total electric generating capacity of more than 315,000 MW.
[3] "EPA policies" include EPA regulations, as well as settlement agreements resulting from EPA's New Source Review enforcement activities. Other factors contributing to the shutdowns in Table 1 include low natural gas prices.
[4] 4,831 MW are slated to retire or convert after 2025.

TABLE 1. Coal Units Retiring or Converting Because of EPA Policies[5]

STATE	MW CLOSING OR CONVERTING	UNITS CLOSING OR CONVERTING
1. Ohio	6,421	40
2. Pennsylvania	5,548	30
3. Alabama	5,166	26
4. Indiana	4,308	25
5. Kentucky	3,471	16
6. Georgia	3,249	15
7. Illinois	2,996	13
8. North Carolina	2,783	20
9. West Virginia	2,737	18
10. Virginia	2,354	16
11. Tennessee	2,299	15
12. Minnesota	2,014	13
13. South Carolina	1,759	14
14. Missouri	1,738	17
15. Arkansas	1,659	2
16. Florida	1,568	7
17. Iowa	1,564	28
18. Oklahoma	1,464	3
19. Massachusetts	1,408	6
20. Texas	1,399	3
21. New Mexico	1,375	5
22. Michigan	1,352	16
23. Maryland	1,319	7
24. Wisconsin	1,287	16
25. Colorado	1,172	11
26. Arizona	822	4
27. Mississippi	706	2
28. Nebraska	637	5
29. Oregon	585	1
30. Louisiana	575	1
31. New York	475	3
32. New Jersey	268	2
33. Utah	172	2
34. Montana	154	1
35. Kansas	92	2
36. Wyoming	49	4
37. South Dakota	22	1
	66,967 MW	410 UNITS

[5] Most of the coal units listed in the table are retiring; 74 units representing 12,440 MW are converting to natural gas, biomass, or another fuel.

TABLE 2. All Coal Units Retiring or Converting[6]

STATE	MW CLOSING OR CONVERTING	UNITS CLOSING OR CONVERTING
1. Ohio	7,751	43
2. Pennsylvania	5,737	33
3. Alabama	5,166	26
4. Indiana	4,748	30
5. North Carolina	4,288	33
6. Illinois	4,261	18
7. Georgia	3,752	17
8. Kentucky	3,471	16
9. Virginia	2,836	21
10. West Virginia	2,737	18
11. Nevada	2,689	8
12. Tennessee	2,299	15
13. Minnesota	2,152	15
14. Utah	2,072	7
15. Iowa	1,832	32
16. South Carolina	1,759	14
17. Missouri	1,755	18
18. Arkansas	1,659	2
19. New York	1,588	13
20. Florida	1,568	7
21. Wisconsin	1,525	23
22. Massachusetts	1,517	7
23. Oklahoma	1,464	3
24. Michigan	1,433	19
25. Texas	1,399	3
26. Washington	1,376	2
27. New Mexico	1,375	5
28. Maryland	1,319	7
29. Colorado	1,172	11
30. Arizona	822	4
31. Nebraska	757	6
32. Mississippi	706	2
33. Oregon	585	1
34. Louisiana	575	1
35. Delaware	360	4
36. New Jersey	291	3
37. Connecticut	181	1
38. Montana	154	1
39. California	129	3
40. Kansas	92	2
41. Wyoming	49	4
42. South Dakota	22	1
	81,423 MW	499 UNITS

[6] Most of the coal units in the table are retiring; 93 units representing 13,890 MW are converting to natural gas, biomass, or another fuel.

The National Rural Electric
Cooperative Association

Comments on

Proposed National Emission Standards for Hazardous Air Pollution: Coal-and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review

Submitted Electronically to:

The Environmental Protection Agency

Air Docket

Attention Docket ID NO. EPA-HQ-OAR-2018-0794

June 23, 2023

by

Rae E. Cronmiller
Environmental Counsel
4301 Wilson Boulevard, EU 11-249
Arlington, VA. 22203-1860

(703) 907-5791 / rae.cronmiller@nreca.coop

correlation requirements are next to impossible to achieve for the proposed fPM limit of 0.010lbs./MMBtu and even more unworkable with the alternative 0.006 lbs./MMBtu proposal.

The EPA cites earlier rulemakings and research projects that in fact reasonably lead to the opposite of EPA′s conclusion of CEMS viability to accurately measure fPM at 0.010 lbs./MMBtu. EPA maintains that the 2012 Portland Cement rulemaking bolsters EPA's contention that CEMS can operate with required accuracy and precision within the proposed fPM range EPA proposes. Roberson, however, points out that in the final Portland Cement rule EPA decided not to require CEMS because of correlation issues. EPA next claims the CEMS requirement for new EGUs validates the proposed requirement here. But again, as Roberson point out since there are no new EGUs, there is no actual required use to validate the CEMS workability for the fPM levels at issue here. Lastly, EPA references an Electric Power Research Institute (EPRI) project whose objective was to perfect a CEMS that would directly measure PM. EPA cites the EPRI effort to somehow show this technology was developed and would allow accurate measurement of fPM at the level proposed here. Roberson, who participated in this earlier effort, recounts that the research effort was terminated without success at least partially because EPA showed no interest in furthering the effort to perfect CEMS.

- *EPA has failed to consider the electric reliability impacts of this rulemaking*

As detailed in the Cichanowicz Report, EPA IPM model base case for this proposal prematurely retired 59 coal-fired units. Many of these units have not, as of the time of this rulemaking, indicated retirement dates near the date when this proposal may become final. Thus, if EPA prediction is wrong, they would be affected by the date this proposal would become final.[6] EPA modeling principally relies on the Inflation Reduction Act associated financial incentives along with the implementation of the 2015 Ozone Transport Federal Implementation Plan (FIP) as the main drivers forcing the retirements of most of the 59 units. EPA' s specific modeling assumptions leading to these units prematurely retiring do not appear anywhere in the docket and yet EPA's Regulatory Impact Analysis (RIA) for this proposal incorporates these assumptions to

[6] Cichanowicz Report at pages 40-43. Table 8-1 listing units retiring in 2030 should read 27 not 23 making the total in Table 8-1 59 units. Tables 8-2 and 8-3 are correct in listing EPA IPM retired units.