from mining, oil and gas extraction. North Dakota has also seen gains in agriculture and forestry activities. These sectors are energy intensive industries, highly dependent on reliable power.[3] Nebraska and South Dakota are similarly reporting substantial increases in GDP. Due to this increase demand, these areas have an elevated risk of reliability concerns. The adoption of CCS as BSER will only heighten this risk, as it poses a threat to the availability of important baseload generation.

70. *Extreme weather*. Extreme weather events in both the winter and summer further illustrate the importance of a balanced and reliable grid. During the summer in Minnkota's service area, MISO currently has the capacity to serve its projected summer needs if wind generation performs as anticipated.[4] However, loss of coal resources and the reliability issues of

(June 30, 2023), https://www.bea.gov/sites/default/files/2023-06/stgdppi1q23.pdf

3 https://www.statista.com/statistics/1065144/north-dakota-real-gdp-by-industry/

4 https://cdn.misoenergy.org/2023%20Summer%20Resource%20Assessment628978.pdf

CCS would put further pressure on wind in a reliability crisis. Loss of diversification of generation resources and dependence on wind exacerbates the risk of under-generation during the extreme cold winter, hot summer, and other weather events.

71. *Costs of Reliability Events to Minnkota and its Members*. During reliability events, the costs to purchase power skyrocket. Minnkota would be exposed to these extreme costs if Minnkota could not meet its own generation needs with its own generation assets.

72. *Other Damages from Reliability Events.* The North Dakota Reliability Study highlights the dramatic repercussions from the loss of units due to the Final Rule. Minnkota would anticipate a loss of jobs at the Young Station. Minnkota employs 200 people in the vicinity of Center, North Dakota. In addition, many subcontractors provide services to the plant on a regular basis. The nearby BNI Coal mine would be impacted or possibly close because it sells lignite to the Young Station. On information and belief, BNI employs approximately 178 persons at the mine. In total, the direct cost to the community from the loss of employment would be staggering.

Impacts from the loss of jobs in the area would have a ripple effect on ancillary industries, such as nearby service stations, reduced demand for customer services, and the social and psychological impacts of job loss on the affected individuals and their families. Premature retirement of units results in irreversible harm that economically damages Minnkota and impacts the entire region.

73. The interruption of power delivery from a grid failure would cause damage to public health. North Dakotans rely on electricity to heat their homes during the extreme winter temperatures of the long winter season. Affordable and consistent power allows for medical providers to provide essential services to the elderly, infirm, and to vulnerable individuals with chronic health conditions. Evidence from grid failures in other areas of the country in winter storms Uri and Elliott show the documented health impacts and morbidity caused by those events. The Final Rule places the portion of the grid serving North Dakota in serious jeopardy of failure and resulting consequences.

74. EPA failed to adequately account for the costs due to a grid failure in the rulemaking. In its service area, Minnkota would anticipate that grid failures would cause end users to suffer economic and real damages such as food spoilage, property damage, lost labor productivity, and loss of life. The North Dakota Reliability Study discusses these damages in more detail in Section D (Modeling Results).

ABSENT A STAY, MINNKOTA WILL SUFFER IMMEDIATE IRREPARABLE HARM

75. Minnkota is harmed by the Final Rule with respect to any alternative the cooperative would pursue to continue to provide reliable and affordable power to its member cooperatives. These options are: (1) Compliance with the Long-Term coal category for Unit 1 and Unit 2; or (2) Retirement of the Milton R. Young Station.

Compliance with the Long-Term Coal Category.

76. The Final Rule would require Minnkota to immediately identify a compliance alternative for the remaining untreated flue gas at the Young Station. To accomplish this task through CCS, Minnkota must immediately begin taking steps to determine the breadth of the impact to the current

design of Project Tundra and any alternatives. These steps include engineering studies, design studies, and purchase contracts. All of that must happen soon, because each increment of delay puts compliance with the Final Rule even further out of reach. Working backwards from a 2032 compliance date, Minnkota is already significantly behind schedule. Designing the current scale of CCS for Project Tundra took almost a decade. Yet the Final Rule requires Minnkota to update that design with a new, expanded CCS system *and* bring it into operation within about half that time.

77. The expected costs involved in complying with the Long-Term Subcategory would be substantial. The additional development costs alone would be projected between $10-40 million. Further studies would need to be conducted to identify an estimate for the remainder of the project. It is very uncertain whether Minnkota could secure additional project partners, funds, or loans to allow for this expenditure.

78. Unlike larger IOU systems, Minnkota does not have investors from which to raise money. Rather, Minnkota often relies upon USDA RUS financing for large capital projects. The process of securing financing

through the RUS requires additional time for completion of environmental review under NEPA. As a small entity cooperative, Minnkota is less nimble at procuring financing and has fewer resources available to meet demand.

Retirement of the Milton R. Young Station.

79. Minnkota has *already* made significant capital expenditures for Project Tundra. As previously mentioned, Project Tundra hinges on the ability of the Young Station to comply with the Final Rule. The Final Rule jeopardizes this capability. If Project Tundra fails as a result, Minnkota, along with its partners, the State of North Dakota, and the Department of Energy, have expended over $90 million towards project development as of March 31, 2024. Those costs are not recoverable, and similar costs will only continue to accrue and accelerate over the next several years of litigation—unless the Final Rule is stayed. Minnkota has spent project costs and will continue expending additional costs during the pendency of the litigation, which, without commercial operation of the project, will not be recoverable.

80. Minnkota must evaluate all alternative baseload generation, including natural gas. But even today's state-of-the-art natural gas combined

cycle units ("Combined Cycles") cannot achieve the 90% capture of CCS that the Final Rule demands. Even if those units could achieve 90% CCS, constructing in-kind MW generation to replace the Young Station would cost approximately $1 billion. That estimate does not include land, water rights, financing fees, escalation, tax, or insurance. To bring that amount of generation into its portfolio by the Final Rule's cliff, Minnkota does not have sufficient time.

81. As a mine-mouth facility, Minnkota would incur costs associated with the BNI mine. These costs include mine closure and reclamation.

82. A summary of the costs of retirement of the Young Station and the construction of natural gas replacement power are:

Activity	**Cost**	**Basis**
Expenditures lost from Project Tundra	$30M	Accounting
Stranded Debt from the Young Station	Unit 1 ($158.5M); Unit 2 ($70.7M) = total $229.2 million upon January 1, 2032	Accounting
Construction of a New Gas Line to Young Station	$60 M($2M per mile)	Vendor estimates

Construction of a Natural Gas Combined Cycle Unit*	$1 billion, which includes the capital cost at $1400 kW and interconnection costs to MISO	Vendor estimates
BNI Mine Reclamation costs	$200-220 M	Accounting
Stranded Debt from the BNI Mine	60-70 M	Accounting
TOTAL	**$1.58-1.61 billion**	

*These costs do not include the cost of constructing or retrofitting a capture facility for the flue gas from a gas unit.

**These costs do not include the cost of shuttering the Young Station.

83. If Minnkota were unable to replace the megawatts from the Young Station prior to the compliance date for the Final Rule of 2032, Minnkota would be faced with increased exposure to market volatility. The costs of purchasing power off the MISO market may expose Minnkota's membership to a current cap of $3,500 per MWh, which could eliminate the entire annual value of the Young Station's generation in less than 4 days.

84. Regardless of which compliance pathway it chooses, Minnkota will need to secure reliable and dispatchable replacement power as result of the Final Rule. Non-dispatchable renewable energy sources (such as wind and solar) cannot satisfy that demand due to their intermittent nature.

85. *Immediate costs to Minnkota's members and consumers.* As a cooperative, Minnkota will be faced with all these near-term costs. Minnkota's members—and ultimately to the rural end users who depend on Minnkota to keep their lights and heat on will bear the costs of the Final Rule.

86. These costs are not recoverable. Equipment cannot be returned. Dollars spent on design, permitting, engineering, and other studies cannot be refunded. Legally binding retirement promises cannot be undone.

87. Moreover, these costs cannot be deferred or delayed until the courts reach a final determination on the merits of the State Petitioners' Petition for Review. At best, Minnkota expects that process to take *at least* 2-3 years. But the Final Rule's compliance deadlines do not give Minnkota any time to spare. On the contrary, haste is of the essence, for several reasons.

88. In sum, if the Final Rule remains in effect while challenges to the Rule are pending, Minnkota will have no choice but to incur significant unrecoverable compliance costs as well as to shoulder the many other substantial, immediate, and irreparable harms described above.

*   *   *

I declare under penalty of perjury under the laws of the United States of America, pursuant to 28 U.S.C. § 1746, that the foregoing is true and correct to the best of my knowledge.

Executed on this 10th day of May, 2024, in Washington, DC.

Robert McLennan

EXHIBIT 18

DECLARATION OF CHRISTOPHER D. FRIEZ

I, Christopher D. Friez, declare as follows:

1. My name is Christopher D. Friez, and I am the Vice President-Land, Associate General Counsel and Assistant Secretary of NACCO Natural Resources Corporation ("NACCO NR").
2. NACCO NR, a subsidiary of NACCO Industries, Inc., through its subsidiary North American Coal, LLC, mines and markets lignite coal primarily as fuel for power generation and provides selected value-added mining services for other natural resources companies. Its corporate headquarters is located in Plano, Texas near Dallas. NACCO NR operates surface lignite coal mines in North Dakota, Mississippi, and Louisiana.
3. NACCO NR is one of the United States' largest miners of lignite coal and among the largest coal producers in the country, producing approximately 23.9 million tons of lignite in 2023.
4. Because lignite has a higher moisture content and a lower heat content than other types of coal, and therefore cannot be transported long distances in a cost-effective manner, most lignite is sold to power plants adjacent or near to the producing mine. If a power plant served by a lignite mine closes, I am not aware of any reasonably viable new market opportunities for the lignite coal.
5. EPA's final "New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule" (the "GHG Rule") will cause immediate, irreparable injury to NACCO NR, its workers, and the communities in which it mines coal in several ways. NACCO NR currently mines and sells lignite coal

to power plants adjacent to its coal mines at the following facilities: Red Hills Generating Facility near Ackerman, Mississippi (served by the Red Hills Mine); Antelope Valley Station near Beulah, North Dakota (served by the Freedom Mine); Leland Olds Station near Center, North Dakota (served by the Freedom Mine); Coal Creek Station near Underwood, North Dakota (served by the Falkirk Mine); and Coyote Station near Zap, North Dakota (served by the Coyote Creek Mine). NACCO NR sells nearly all of its lignite coal production to these facilities. The GHG Rule effectively requires these facilities to install costly carbon capture technology, co-fire on an alternative fuel source, completely shift their fuel source to natural gas, or shut down by January 1, 2032. The fuel switching or retirement of these facilities will cause NACCO NR to significantly downsize, or close, the coal mines which currently supply these facilities, resulting in the write off of tens of millions of dollars of investment by NACCO NR. This downsizing or closure will result in hundreds of millions of dollars of stranded investment at these facilities and mines, much of which would likely be passed through to North Dakota and Minnesota ratepayers, cooperative members, and small municipalities. The closure of the Red Hills Mine would result in the loss of over $50 million of direct investment made by NACCO NR to date. In addition, early closure of these facilities would result in the loss of over a thousand jobs and the loss of revenue for which NACCO NR is contracted to receive well into the future. NACCO NR believes that all of these injuries are preventable if the court stays and ultimately overturns the GHG Rule.

6. The administrative record and other public statements by the owners and operators of these facilities express major challenges with the emission reduction requirements of the GHG Rule. First, it is widely expressed that carbon capture and storage ("CCS") has not been

achieved at the scale suggested by the EPA, and that CCS is cost prohibitive. The EPA also fails to consider the significant geologic storage or CO_2 pipeline transportation needs that CCS would require, not to mention significant permitting requirements for injection wells and storage areas. Second, these facilities are not currently equipped, without significant capital investment, to co-fire on natural gas, nor are large enough quantities of natural gas available on site at these facilities today to meet the fuel needs such co-firing would require – major expensive retrofits would be required (if even feasible) and substantial pipeline construction, at significant expense, would need to occur. These are the only two emission reduction options that would allow these facilities to continue to be fueled by coal longer than January 1, 2032. Because of the major expense, technological challenges, geologic challenges, and tight timeframe, it is highly likely these facilities will be required to shut down by January 1, 2032 due to the inability to meet the requirements of the GHG Rule for any number of reasons.

North Dakota—Coyote Creek Mine

7. Through a wholly-owned subsidiary, Coyote Creek Mining Company, L.L.C. ("CCMC"), NACCO NR developed the Coyote Creek Mine in Mercer County, North Dakota, about 70 miles northwest of Bismarck. The Coyote Creek Mine began making lignite deliveries to Coyote Station, a 427-megawatt power plant, in 2016.
8. If Coyote Station cannot meet the requirements of the GHG Rule, it will be required to close. The purpose of the Coyote Creek Mine is to support, and to provide a fuel source for, Coyote Station. Thus, if the power plant closes, Coyote Creek Mine would close as well. If that were to happen, the 90-person mine workforce would be laid off, CCMC would go out of business, and the local community and the State of North Dakota would be

deprived of the valuable spin-off benefits and taxes and royalties described below in paragraphs 14 and 15.

9. To develop the mine and comply with its contractual obligations, CCMC permitted an area large enough to supply coal for the 25-year life of the contract with Coyote Station. CCMC spent over $6 million to permit the acreage needed for 25 years. If the power plant and mine must close on January 1, 2032, CCMC will lose the dollars spent to permit lands that will never be needed for mining. In addition, $30 million of mine development costs are being amortized over the life of the mine. If that life is cut short by 10 years, roughly $10 million in costs are lost.

10. In addition to permitting and mine development costs, CCMC incurred equipment costs of around $80 million for mine startup and operation through the life of the mine. Again, these costs are being amortized over the life of the mine and if the mine is forced to close early, it is likely $25-30 million of those costs are lost because full amortization cannot be realized and the equipment will likely have a very low resale value.

11. Due to the cost-plus nature of the contract under which CCMC supplies fuel to Coyote Station, many of CCMC's costs and obligations are passed through to the public utilities that jointly own Coyote Station—Otter Tail Power Company, Northern Municipal Power Agency, Montana-Dakota Utilities Company, and NorthWestern Corporation. In the end, the utilities, and more specifically their ratepayers and members, will pay these costs. In return, the ratepayers and members to whom the costs of Coyote Station are passed on will not have received the benefit of the low-cost and reliable power that otherwise would be delivered by Coyote Station. Their stranded investment in the Coyote Creek Mine will be lost.

North Dakota—Falkirk Mine

12. NACCO NR, through its wholly-owned subsidiary, The Falkirk Mining Company ("Falkirk"), operates the Falkirk Mine near Underwood, North Dakota, about 50 miles north of Bismarck. The Falkirk Mine annually produces between 7 million and 9 million tons of lignite for Coal Creek Station, a two-unit 1100-megawatt power plant owned by Rainbow Energy Center.

13. The owner of Coal Creek Station has spent tens of millions of dollars to study the implementation of CCS at the facility. In the administrative record, the owner cites a myriad of obstacles to implementing CCS, including not enough time to comply, increasing costs, deficient incentives to meet the economic requirements, labor shortages, and others, including the unproven ability to capture 90 percent of the CO_2 emissions. If CCS cannot be fully implemented by 2032, the facility will be forced to shift to an alternative fuel source, if that is even technologically feasible, or close.

14. If Coal Creek Station shifts to an alternative fuel source or closes, the adjacent Falkirk Mine will also be forced to close and incur a layoff of the entire staff and workforce, which will be acute on numerous levels. According to an economic report prepared by North Dakota State University, a true and correct copy of which is attached as Attachment A, in 2021, the latest year for which actual data is currently available, "The combination of coal mining, coal conversion, coal-fired electricity generation, and electricity transmission and distribution was estimated to have 3,300 direct jobs in North Dakota in 2021." "The lignite industry also generated over $1 billion in labor income, which represents wages, salaries, benefits, and sole proprietors's income." For the four hundred plus employees that stand to

lose their jobs if the Falkirk Mine closes, their lives, and their families' lives, will be drastically impacted.

15. Also, a mine closure would have a substantial impact across several counties and cities in North Dakota. Like all mining companies, Falkirk pays a coal severance tax of 37.5 cents on each ton of lignite mined. In 2023, Falkirk paid approximately $2,500,000 in coal severance taxes and NACCO NR's neighboring Freedom Mine paid approximately $4,500,000 in severance taxes. Under North Dakota law, 30% of revenue from the 37.5 cent tax is used to fund a Constitutional Trust Fund administered by the Board of University and School Lands. The other 70% is shared among the coal producing counties in the State, which is further apportioned as follows: 40% to the county general fund; 30% to the cities within the county, and 30% to the school districts. Absent a stay of the GHG Rule, if these mines are forced to shut down, this will impact education, law enforcement, and social services throughout the State of North Dakota.

16. Further, the GHG Rule is creating an immediate impact on the operation of the Falkirk Mine to the detriment of the local community. At the Falkirk Mine, decisions regarding large capital expenditures must be made years in advance due to the amount of time it takes to finance, acquire, transport, assemble and test equipment. A decision must be made now to acquire an additional dragline for the Falkirk Mine to meet customer coal demands and contractual obligations. A used dragline must be acquired now at a cost of approximately $30 million so the dragline can be purchased, transported, reconstructed and placed into service by late 2026 to meet these needs.

17. Due to their enormous size and complexity, it takes years for a used dragline to become operational at a new location. Draglines weigh millions of pounds and must be

disassembled for transport (by rail and truck) to its new location. The parts and equipment constituting the dragline are transported in dozens of modular units to the new location. Upon arrival, the equipment is refurbished, re-assembled, erected, and tested. This work is done by private contractors, including truckers, welders, electricians, mechanical and electrical engineers, and software programmers.

18. Because of this extensive and time-consuming process, Falkirk must acquire the $30 million dragline now, to become operational by late 2026, only to potentially close the mine at the end of 2031, losing almost all of its substantial investment in this piece of equipment, which will be worth only scrap value if the mine is shut down.

North Dakota – Coteau Freedom Mine

19. NACCO NR, through its wholly-owned subsidiary, The Coteau Properties Company ("Coteau"), operates the Freedom Mine near Beulah, North Dakota, about 75 miles northwest of Bismarck. The Freedom Mine annually produces between 12 million and 14 million tons of lignite for Antelope Valley Station ("AVS"), a two-unit 900-megawatt power plant, Leland Olds Station ("LOS"), a 660-megawatt power plant, and Dakota Gasification Company ("DGC"), a Synfuels plant, all owned by Basin Electric Power Cooperative ("Basin").

20. The administrative record contains an express statement from Basin providing that it cannot comply with the GHG Rule standards. Basin states that the CCS requirement is cost prohibitive, requires too great an energy load, and has not been shown to achieve the required 90 percent capture rate – and Basin will not be able to design, permit and construct CCS at its coal-fired facilities by the required compliance date.

21. Similar to Falkirk, a closure and resulting layoff at Freedom Mine would be devastating to the local community. The combination of over 400 high paying jobs at the Freedom Mine alone, along with approximately 600 more at the combined facilities of AVS, LOS, and DGC are the backbone of a 100 mile radius of families' livelihoods and economic activity for central North Dakota, including the neighboring towns of Beulah and Hazen. Without the employment provided by these facilities, the towns of Beulah and Hazen would nearly vanish, along with any economic activity in the region.

22. NACCO NR, at its Freedom Mine, currently has about $130 million worth of property, plant, and equipment which would require accelerated depreciation if the mine is closed early because of the GHG Rule. In addition to that, there is another $70 million in lease depreciation that would be largely unrealized, along with approximately $37 million in warehouse inventory that would have little to no value if the mine were closed early. Finally, a shut down of the Freedom Mine would result in a lost payroll of over $60 million annually.

23. A shut down at AVS or LOS also affect the economics and operating costs of DGC. DGC enjoys a lower price for its lignite coal input based upon sharing in the volume of coal needed to operate AVS and LOS. Because of economies of scale and shared costs over a larger number of tons, if AVS and LOS are shut down, the coal costs for DGC increase exponentially, causing the economics of that facility to be strained as well, and putting it in danger of closing.

24. Beyond the impacts of a shut down, the GHG Rule is creating an immediate impact on the operation of the mine to the detriment of the local community. At the Freedom Mine, as with Falkirk, decisions regarding large capital expenditures must be made years in advance

due to the amount of time it takes to finance, acquire, transport, assemble and test equipment. There are numerous decisions relating to equipment purchases, repairs, and other capital requirements that must be delayed or decisions altered for short term requirements rather than long term decision-making, creating higher future costs and less efficient operations, because of the uncertainty of the GHG Rule and the outcome of litigation.

Mississippi

25. NACCO NR has owned and operated the Red Hills Mine near Ackerman, Mississippi, since 2002. On an annual basis, the Red Hills Mine produces approximately 2.4-2.8 million tons of lignite. Lignite from the Red Hills Mine is used as a fuel supply at the adjacent Red Hills Generating Facility, a 440-megawatt power plant that provides electricity to the Tennessee Valley Authority.
26. The Red Hills Generating Facility will face the same GHG Rule compliance issues as the other facilities.
27. NACCO NR provides lignite to the Red Hills Generating Facility pursuant to a supply agreement that runs through 2032. The agreement, however, also includes two ten-year extension options that, if exercised, would extend the agreement to 2052.
28. Based on NACCO NR's geological data, there are enough proven lignite reserves in the vicinity of the Red Hills Mine to support mining until at least 2052. The most efficient way to mine the reserves would have been to shift approximately 6 miles of Mississippi Highway 9, which bisects the Red Hills Mine area in a north-south direction, about 2 miles to the east. However, because of regulatory uncertainty much like the uncertainty not

granting a stay to the GHG Rule would cause, the decision was made to cross Mississippi Highway 9 by constructing an underpass, rather than move the highway.

29. NACCO NR currently has assets valued at over $50 million at the Red Hills Mine that will likely be lost as stranded investments if the GHG Rule is implemented.

30. Finally, the effects of the GHG Rule cannot be considered in a vacuum. EPA promulgated revisions to the MATS rule on May 7, 2024 that significantly reduced the filterable particulate matter (fPM) standard and removed the lignite subcategory compliance standard for mercury. Unfortunately, in addition to numerous other issues, the compliance dates for the two rules are mis-aligned. To comply with the fPM and/or mercury standards, power plants need to decide whether to spend the significant capital required to attempt to comply with MATS, if compliance is even possible, while at the same time weighing whether they can even operate past January 1, 2032 anyway. If facilities must presume they are required to shut down before January 1, 2032 anyway, it is unlikely they will invest capital to comply with the MATS rule.

31. I, Christopher D. Friez, declare under penalty of perjury under the laws of the United States that the foregoing is true and correct to the best of my knowledge.

Christopher D. Friez
NACCO Natural Resources Corporation

Dated: May 10, 2024

Attachment A

to the Declaration of Christopher D. Friez

NDSU Agribusiness and Applied Economics Report No. 819-S March 2023

North Dakota Lignite Energy Industry

Economic Contribution Analysis

Report Content

Preface

This report is the latest biennial assessment of the economic contribution of the North Dakota lignite energy industry.

Data for this study came from industry surveys, state and federal agencies, and other secondary sources,

The definition of the lignite energy industry and methods used to estimate its economic contribution are consistent with studies examining the economic contribution of other industries in the state. As usual, these studies are snapshots in time and economic contributions often vary from year to year with commodity-based industries.

Industry Highlights

The following figures are based on activity during 2021 and projections of industry output in 2022. All values include direct and secondary economic effects.

North Dakota Lignite Energy Industry in 2021

- $5.64 billion gross business volume
  - $0.9 billion from mining
  - $3.2 billion from coal conversion and electricity generation
  - $1.5 billion from transmission/distribution
- 12,800 jobs (direct and secondary)
  - 3,300 jobs supported by mining
  - 8,400 jobs supported by coal conversion and electricity generation
  - 1,050 jobs supported by transmission/distribution
- $119 million in local and state government revenues

North Dakota Lignite Energy Industry in 2022

- $5.75 billion gross business volume
  - $0.8 billion from mining
  - $3.2 billion from coal conversion and electricity generation
  - $1.7 billion from transmission/distribution
- 12,000 jobs (direct and secondary)
  - 3,250 jobs supported by mining
  - 7,725 jobs supported by coal conversion and electricity generation
  - 1,060 jobs supported by transmission/distribution
- $104 million in local and state government revenues

**Bangsund is a Research Scientist, Department of Agribusiness and Applied Economics and Hodur is Director, Center for Social Research, North Dakota State University

Understanding the Numbers

Economic contribution assessments measure the gross size of an industry or economic sector.

Size is estimated by combining ***direct*** or first-round effects (i.e., sales, spending, and/or employment) with economic modeling to estimate secondary effects of business-to-business transactions (***indirect***) and household spending for goods and services (***induced***).

Economic measures frequently used in economic contribution assessments:
- **Labor income** – earnings of workers and sole proprietors
- **Employment** – wage and salary jobs and sole proprietor/self-employed jobs
- **Gross business volume** – includes direct sales of products and services of the industry being measured, and sum of all business-to-business and household-to-business transactions associated with indirect and induced economic activity
- **Value-added** – represents share of gross state product

An overview and additional information on study methods, data sources, and economic definitions are appended to the end of this report.

Composition of Lignite Energy Industry

Coal Mining: this segment involves the process of extracting lignite coal and delivering it to conversion facilities.

Coal Gasification: this segment involves converting lignite coal into chemicals and other products. It is grouped with electricity generation segment of the industry.

Electricity Generation: this segment burns lignite coal to produce electricity.

Transmission and Distribution: this segment includes moving electricity to local (in-state) distributors and exporting electricity to out-of-state markets.

Industry Contribution 2021

Coal mining had 1,131 direct jobs; business activity relating to coal mining operations supported another 1,220 jobs. Personal spending on goods and services by employees working in the coal mining sector and employees of businesses affected by coal mining supported an additional 960 jobs. The combined effects on statewide employment from coal mining was estimated at 3,300 jobs. Other economic effects from coal mining included $300 million in labor income and $915 million in gross business volume.

Coal conversion and electricity generation from lignite was estimated to have nearly 1,700 direct jobs, and business activity relating to those lignite operations supported another 4,680 jobs. Personal spending on goods and services by employees working in the coal conversion and generation activities and employees of businesses affected by those activities supported an additional 2,070 jobs. The combined direct, indirect, and induced effects on statewide employment from coal conversion and electricity generation was estimated at 8,400 jobs. Other economic effects from coal conversion and electricity generation included $670 million in labor income and nearly $3.2 billion in gross business volume.

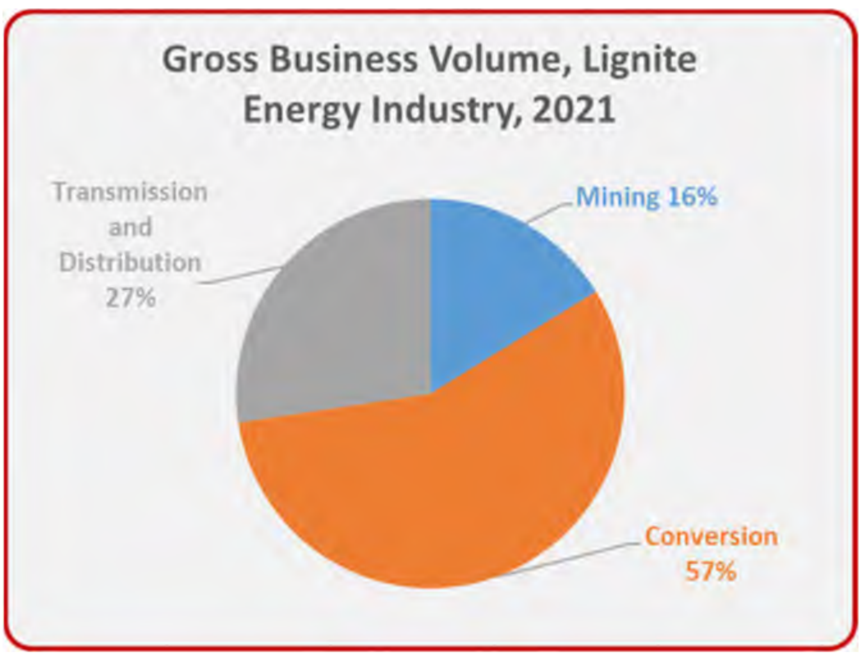
Electricity transmission and generation from lignite-based activities was estimated to have 480 direct jobs; business activity relating to those lignite operations supported another 290 jobs. Personal spending on goods and services by employees working in coal-related electricity transmission and distribution and employees of businesses affected by those activities supported an additional 280 jobs. The combined direct, indirect, and induced effects on statewide employment from coal-related electricity transmission and distribution was estimated at 1,060 jobs. Other economic effects from transmission and distribution included $84 million in labor income and $1.5 billion in gross business volume.

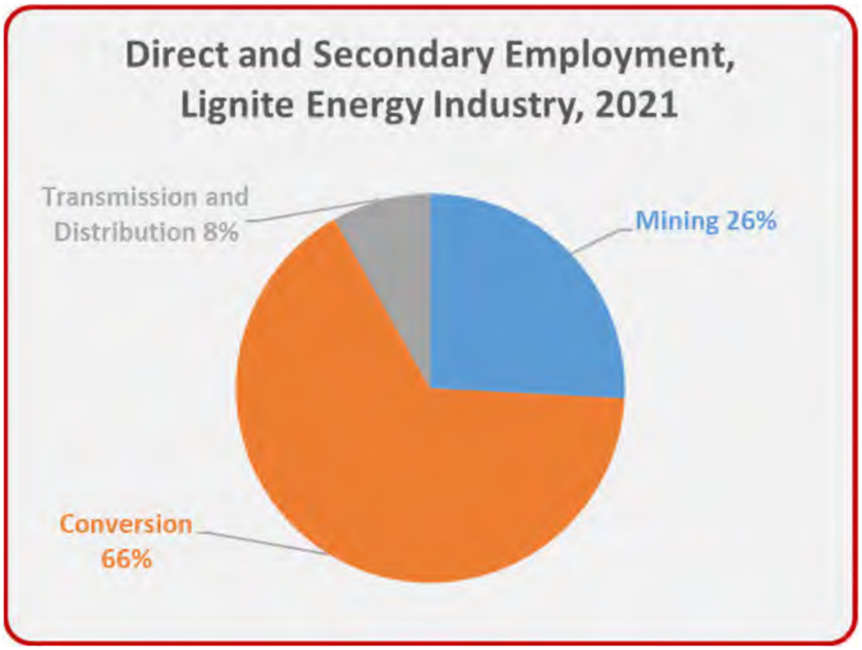
The combination of coal mining, coal conversion, coal-fired electricity generation, and electricity transmission and distribution was estimated to have 3,300 direct jobs in North Dakota in 2021. These lignite coal activities supported about 6,190 jobs through business purchases of goods and services in the state. The combined personal spending of employees in the Lignite Industry, and employees of businesses involved with supplying goods and services to the industry supported another 3,310 jobs. Collectively, the industry was estimated to support 12,800 jobs in the state.

The lignite industry also generated over $1 billion in labor income, which represents wages, salaries, benefits, and sole proprietor's income. The industry also contributed $2 billion to the state's gross domestic product, and the industry's gross business volume was estimated at $5.6 billion.

Direct, Indirect, and Induced Economic Effects, Key Economic Metrics, North Dakota Lignite Industry, 2021				
Industry Segment/Type of Economic Effect	Employment[1]	Labor Income	Value-added	Output
Coal Mining		-------------------- millions 2021 $ --------------------		
Direct effects	1,131	165	227	560
Indirect effects	1,220	84	152	270
Induced effects	960	51	84	85
Total economic effects	3,311	300	463	915
Electricity Generation and Coal Conversion				
Direct effects	1,694	228	240	1,728
Indirect effects	4,680	332	568	1,120
Induced effects	2,070	110	182	331
Total economic effects	8,444	671	990	3,178
Electricity Transmission and Distribution				
Direct effects	483	50	453	1,386
Indirect effects	290	19	69	111
Induced effects	285	15	25	45
Total economic effects	1,058	84	547	1,543

[1] Employment represents total jobs, and does not represent employment in FTE.





Direct, Indirect, and Induced Economic Effects, Key Economic Metrics, North Dakota Lignite Industry, 2021

Type of Economic Effect	Employment[1]	Labor Income	Value-added	Output
ND Lignite Industry		-------------------- millions 2021 $ --------------------		
Direct	3,308	443	919	3,674
Indirect	6,190	436	789	1,501
Induced	3,310	177	291	461
Total	**12,808**	**1,056**	**1,999**	**5,636**

[1] Employment represents total jobs, and does not represent employment in FTE.

Industry Contribution 2022 (projected)

The following figures and values were based on an industry survey soliciting estimates of calendar year 2022 business activities, although the survey was administered prior to yearend. Firms were asked to estimate what their 2022 revenues and expenditures would be based on data available at the time of the survey and augment that information with expected activities for the remaining months in 2022. Data provided by the industry for 2022 is treated as a projection. However, the projection is considered a reasonable estimate of 2022 since, in many cases, the estimates included actual revenues and expenditures for 10 to 11 months of 2022.

Coal mining had 1,170 direct jobs; business activity relating to coal mining operations supported another 1,090 jobs. Personal spending on goods and services by employees working in the coal mining sector and employees of businesses affected by coal mining supported an additional 990 jobs. The combined effects on statewide employment from coal mining was estimated at 3,250 jobs. Other economic effects from coal mining included $300 million in labor income and $830 million in gross business volume.

Coal conversion and electricity generation from lignite was estimated to have 1,630 direct jobs, and business activity relating to those lignite operations supported another 4,240 jobs. Personal spending on goods and services by employees working in the coal conversion and generation activities and employees of businesses affected by those activities supported an additional 1,850 jobs. The combined direct, indirect, and induced effects on statewide employment from coal conversion and electricity generation was estimated at 7,720 jobs. Other economic effects from coal conversion and electricity generation included $620 million in labor income and over $3.2 billion in gross business volume.

Electricity transmission and generation from lignite-based activities was estimated at 470 direct jobs; business activity relating to those lignite operations supported another 300 jobs. Personal spending on goods and services by employees working in coal-related electricity transmission and distribution and employees of businesses affected by those activities supported an additional 280 jobs. The combined direct, indirect, and induced effects on statewide employment from coal-related electricity transmission and distribution was estimated at 1,050 jobs. Other economic effects from transmission and distribution included $86 million in labor income and $1.7 billion in gross business volume.

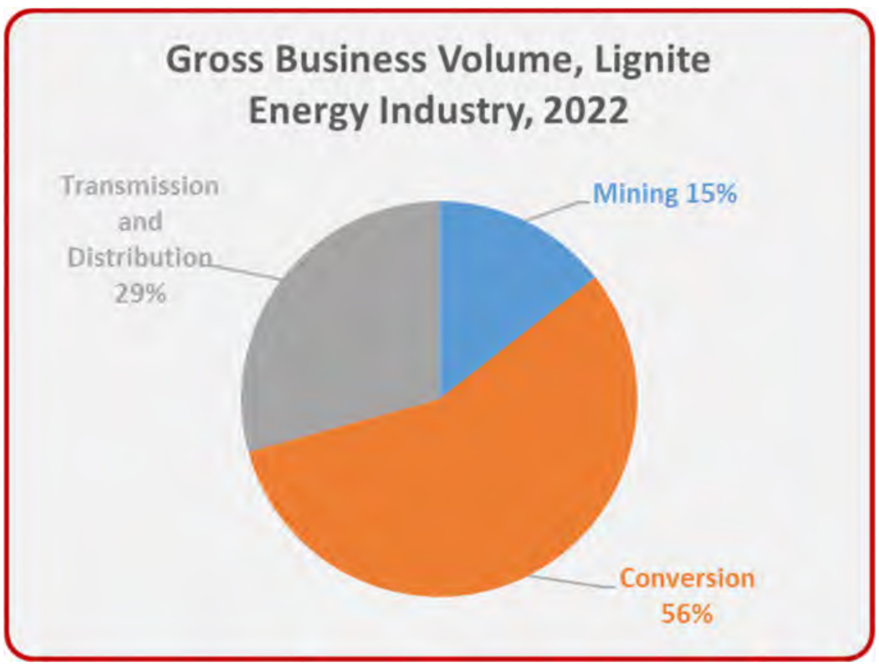
The combination of coal mining, coal conversion, lignite coal-fired electricity generation, and electricity transmission and distribution was estimated to have 3,270 direct jobs in North Dakota in 2022. These lignite coal activities supported about 5,630 jobs through business purchases of goods and services in the state. The combined personal spending of employees in the Lignite Industry, and employees of businesses involved with supplying goods and services to the industry supported another 3,120 jobs. Collectively, the industry was estimated to support 12,020 jobs in the state.

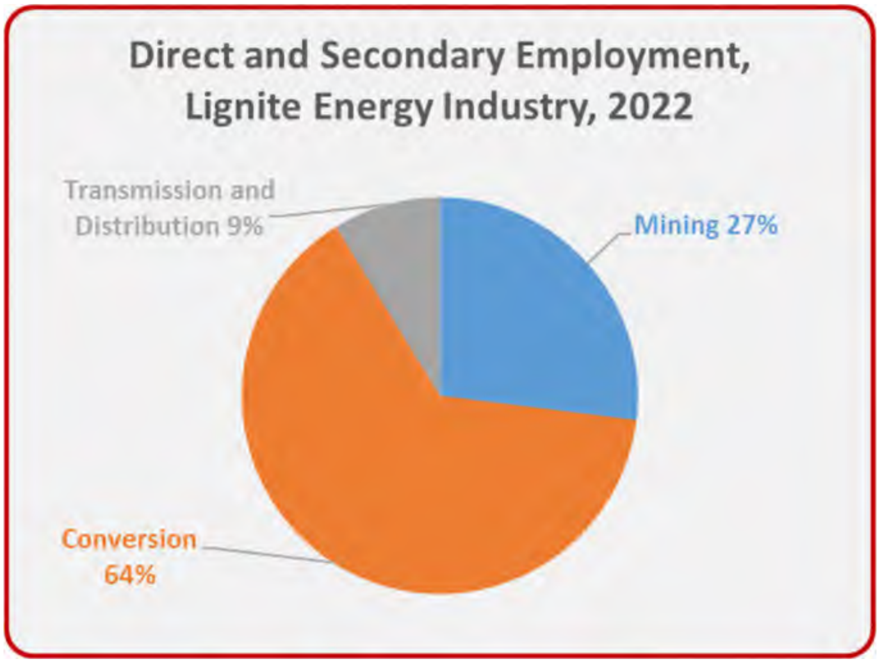
The lignite industry also generated over $1 billion in labor income, which represents wages, salaries, benefits, and sole proprietor's income. The industry also contributed nearly $2.2 billion to the state's gross domestic product, and the industry's gross business volume was estimated at $5.8 billion.

Direct, Indirect, and Induced Economic Effects, Key Economic Metrics, North Dakota Lignite Industry, Projected 2022

Industry Segment/Type of Economic Effect	Employment[1]	Labor Income	Value-added	Output
Coal Mining		-------------------- millions 2022 $	--------------------	
Direct effects	1,168	177	219	537
Indirect effects	1,090	76	123	207
Induced effects	990	53	87	88
Total economic effects	3,248	306	430	832
Electricity Generation and Coal Conversion				
Direct effects	1,633	225	510	2,008
Indirect effects	4,240	295	534	935
Induced effects	1,850	99	163	297
Total economic effects	7,723	619	1,208	3,239
Electricity Transmission and Distribution				
Direct effects	473	51	473	1,525
Indirect effects	300	20	47	116
Induced effects	280	15	25	45
Total economic effects	1,053	86	545	1,687

[1] Employment represents total jobs, and does not represent employment in FTE.





Direct, Indirect, and Induced Economic Effects, Key Economic Metrics, North Dakota Lignite Industry, 2022 (projected)

Type of Economic Effect	Employment[1]	Labor Income	Value-added	Output
ND Lignite Industry		----------------------	millions 2022 $	----------------------
Direct	3,274	453	1,202	4,070
Indirect	5,630	391	704	1,258
Induced	3,120	167	275	430
Total	**12,024**	**1,011**	**2,182**	**5,758**

[1] Employment represents total jobs, and does not represent employment in FTE.

Government Revenues 2021

Government revenues are often used as a measure of how effectively an industry supports public services. In North Dakota, the most common sources of in-state public revenues are severance taxes, sales and use taxes, property taxes, and income taxes. A host of other taxes and revenue sources are often tracked in economic contribution and impact assessments, but those sources have varying levels of contribution to government revenue.

The lignite industry was estimated to contribute $64.5 million in government revenues directly from the firms in the industry. Tax revenues arising from secondary business activity were estimated to generate an additional $54.5 million in state and local government revenues. A total of $119 million in state and local tax revenues were generated by the Lignite Industry in North Dakota in 2021.

Coal conversion and coal severance taxes were estimated at $26.5 million. Other substantial contributions to state and local government revenues from secondary economic effects were from sales taxes ($25 million) and property taxes ($19.5 million).

State and Local Government Revenues, Lignite Industry, North Dakota, 2021

Government Revenue	Paid Directly by the Industry	Collected from Indirect and Induced Activity	Total Collections
	---------------------- 000s 2021 $ ----------------------		
Coal Severance Tax	10,518	---	10,518
Coal Conversion Tax	15,991	---	15,991
Sales, Property, and Corporate Income Taxes (reported in survey data)	25,861	---	25,861
Social Insurance Tax	1,952	1,247	3,200
Personal Income Tax	3,039	2,377	5,416
Sales Tax	see above	25,336	25,336
Property Tax	see above	19,531	19,531
Corporate Income Tax	see above	1,362	1,362
Other Taxes	2,666	1,438	4,104
Non Taxes	4,568	3,222	7,789
Totals	**64,595**	**54,512**	**119,107**

Government Revenues 2022 (projected)

The lignite industry was projected to contribute $53 million in government revenues directly from the firms in the industry. Tax revenues arising from secondary business activity, based on projections of industry activity, were estimated to generate an additional $50.6 million in government revenues. A projected total of $103.5 million in state and local tax revenues were created by the Lignite Industry in North Dakota in 2022.

Coal conversion and coal severance taxes were estimated at $15.8 million. Other substantial contributions to state and local government revenues from secondary economic effects were from sales taxes ($23.5 million) and property taxes ($18 million).

State and Local Government Revenues, Lignite Industry, North Dakota, 2022 (projected)

Government Revenue	Paid Directly by the Industry	Collected from Indirect and Induced Activity	Total Collections
	---------------------- 000s 2022 $	----------------------	
Coal Severance Tax	10,450	---	10,450
Coal Conversion Tax	5,360	---	5,360
Sales, Property, and Corporate Income Taxes (reported in survey data)	25,667	---	25,667
Social Insurance Tax	1,996	1,183	3,179
Personal Income Tax	3,107	2,264	5,371
Sales Tax	see above	23,457	23,457
Property Tax	see above	18,082	18,082
Corporate Income Tax	see above	1,310	1,310
Other Taxes	2,349	1,331	3,680
Non Taxes	4,024	3,003	7,027
Totals	**52,953**	**50,630**	**103,583**

Share of State Economy

A key means of placing an industry contribution study into context is showing its share of a broader economy. The lignite energy industry represents an important share of the North Dakota's economy. The lignite energy industry represented 2.6 percent of the state's gross state product and 4 percent of the state's gross business volume. The industry represented about 2.8 percent of the state's total labor income. The industry represents about 1.2 percent of all state and local government revenues.

The lignite energy industry share of employment was 2.3 percent of statewide employment. Those shares are based on a state total for both wage and salary jobs and sole proprietors/self employed jobs. The industry's share of the state economy was not estimated for 2022 as state-level data was unavailable prior to completing the study.

ANNUAL SHARE OF STATE TOTALS, North Dakota Lignite Energy Industry

Industry Segment	Labor Income	Value-added (GSP)	Total Output	State and Local Government Revenues
State-level Values for 2021	$37.3 billion	$77.0 billion	$142.7 billion	$9.954 billion
Mining	0.81%	0.60%	0.64%	---
Conversion	1.80%	1.29%	2.23%	---
Transmission and Distribution	0.23%	0.71%	1.08%	---
All Segments	2.83%	2.60%	3.95%	1.20%

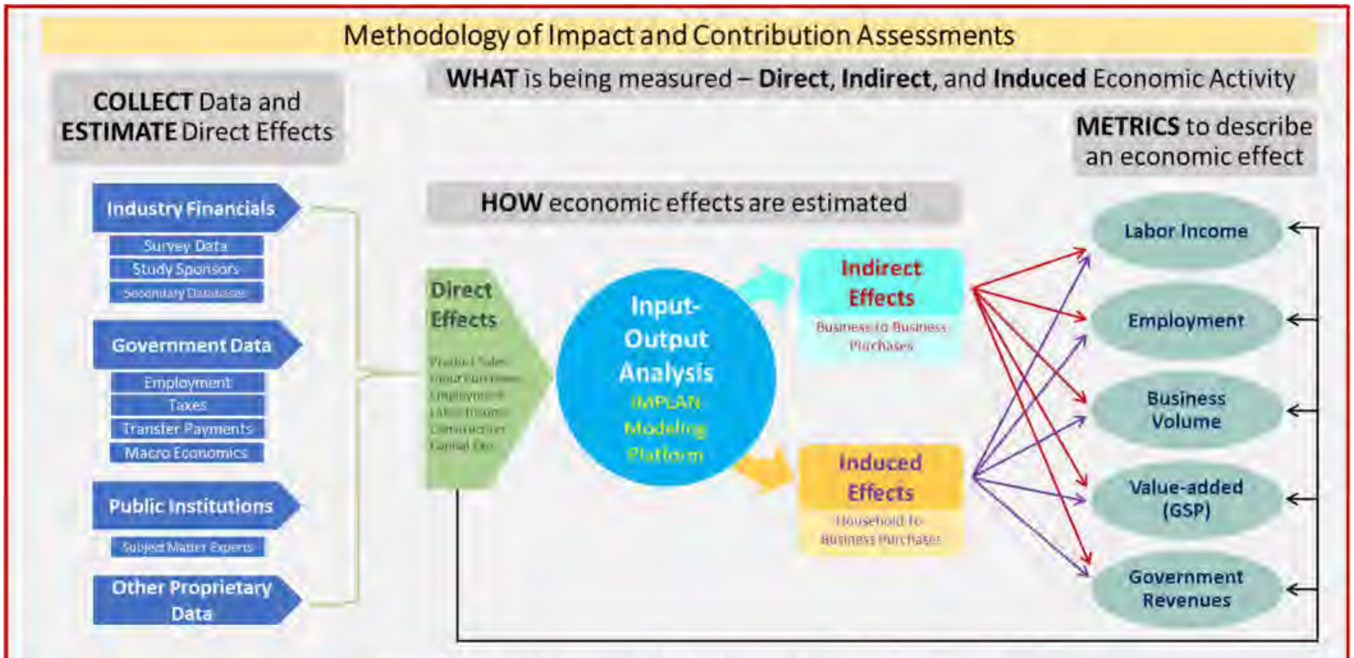
ANNUAL SHARE OF STATE EMPLOYMENT, North Dakota Lignite Energy Industry

Industry Segment	Total Employment	Wage and Salary	Self-employed
State-level Values for 2021	557,702	434,811	122,691
Mining	0.59	3184#	3175#
Conversion	1.51	31k<#	31;9#
Transmission and Distribution	0.19	314:#	313;#
		#	#
All Segments	2.30%	419:(#	4169(#

Supplemental Materials

Economic Contribution Analysis

An economic contribution assessment measures the gross size of some aspect or component of an economy, and is usually measured in conjunction with the overall size of a given economy over a specified period. Size is estimated by combining direct or first-round effects (e.g., industry expenditures, business sales, new employment) with economic modeling to estimate how those first round effects generate business-to-business transactions and household spending on consumer goods and services. Both of those conduits for economic output can be framed using labor income, employment, value-added, gross business volume and government revenues.



Source: DA Bangsund, Agribusiness and Applied Economics, North Dakota State University

Key Terms and Concepts

Direct Effects: First-round of payments for services, labor, and materials and/or sales of an industry's products.

Indirect Effects: Economic activity created through purchases of goods and services by businesses.

Induced Effects: Economic activity created through purchases of goods and services by households.

Industry Output and Gross Business Volume: Industry output is the value of all goods and services produced and supported by an industry. In most industries, output is largely synonymous with sales; however, for some sectors output also includes changes in product inventory. For lignite energy industry, direct output includes both sales and inventory adjustments.

When output from business-to-business transactions (*indirect*) and households-to-businesses (*induced*) are measured, they also are described as the *sum of gross receipts* as annual adjustments to inventories are largely unquantified and not distinguished from sales. *Gross business volume* (GBV) therefore includes direct output/sales and includes secondary sales from indirect and induced economic activity.

Value-added: Value-added is synonymous with measures of gross domestic product (GDP) and gross state product (GSP), are some of the most commonly used economic measures to indicate the economic size and change in economic output. However, official government estimates of GDP and GSP do not include secondary economic effects generated by any industry. For lignite energy industry, official government estimates are primarily limited to coal mining, coal conversion, and transmission/distribution. Economic contribution assessments include secondary economic effects, and include GSP from those effects, thereby providing a more realistic and representative portrait of an industry.

Key components of value-added include labor income, consumption of fixed capital, profits, business current transfer payments (net), and income derived from dividends, royalties, and interest. In nontechnical terms, value-added is equal to product value minus production inputs. For example, value-added from coal mining would be the value of coal sold less the value of the inputs consumed in mining the coal. Depreciation charged to durable assets (e.g., buildings, pipelines, processing equipment) are not included in value-added measures.

Employment Compensation: Wages, salaries, and benefits earned by an employee.

Proprietor Income: Payments received by self-employed individuals and unincorporated business owner/operators.

Labor Income: Wages, salaries, and benefits for employees and compensation for self-employed individuals.

Input-output Analysis (I-O): Mathematical application of the interdependence among producing and consuming sectors in an economy.

I-O Matrix: Depiction of an economy using a grid of rows and columns that represents consumption and production for each economic sector in an economy.

Intermediate Inputs: Goods and services consumed in one year to produce another good or service. Intermediate inputs do not include expenditures for capital inputs used for multiple production seasons (e.g., machinery, buildings).

Capital Inputs: Represent the use of inputs to produce another good or service that are not consumed in one production season and are subject to depreciation. *Capital expenditures* represent the purchase of those depreciable assets.

Industry Balance Sheet: Dividing an industry or economic sector into various components for use in estimating the economic effects using input-output analysis. Components of the balance sheet include measures of output, wage and salary employment, self-employment, payroll and proprietor income, other property type income, taxes on production and imports, and intermediate inputs.

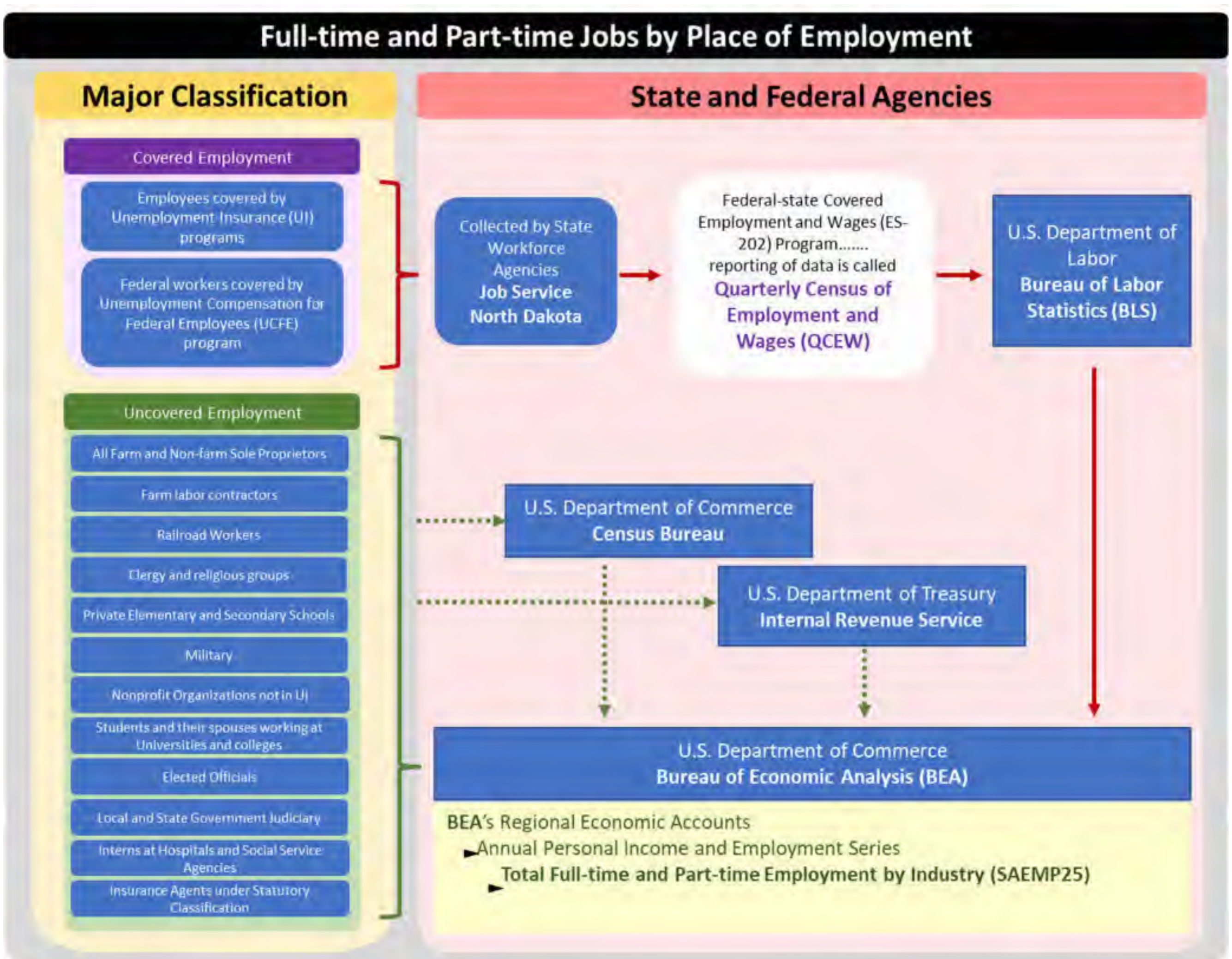
Institutions: Represent governments and other non-private entities consuming goods and services in an economy.

Households: Represent one or more individuals in a specific living arrangement for which income from all sources is used to purchase goods and services.

North American Industry Classification System (NAICS): Government classification system for all goods and services produced in the economy.

Employment Sources and Measures

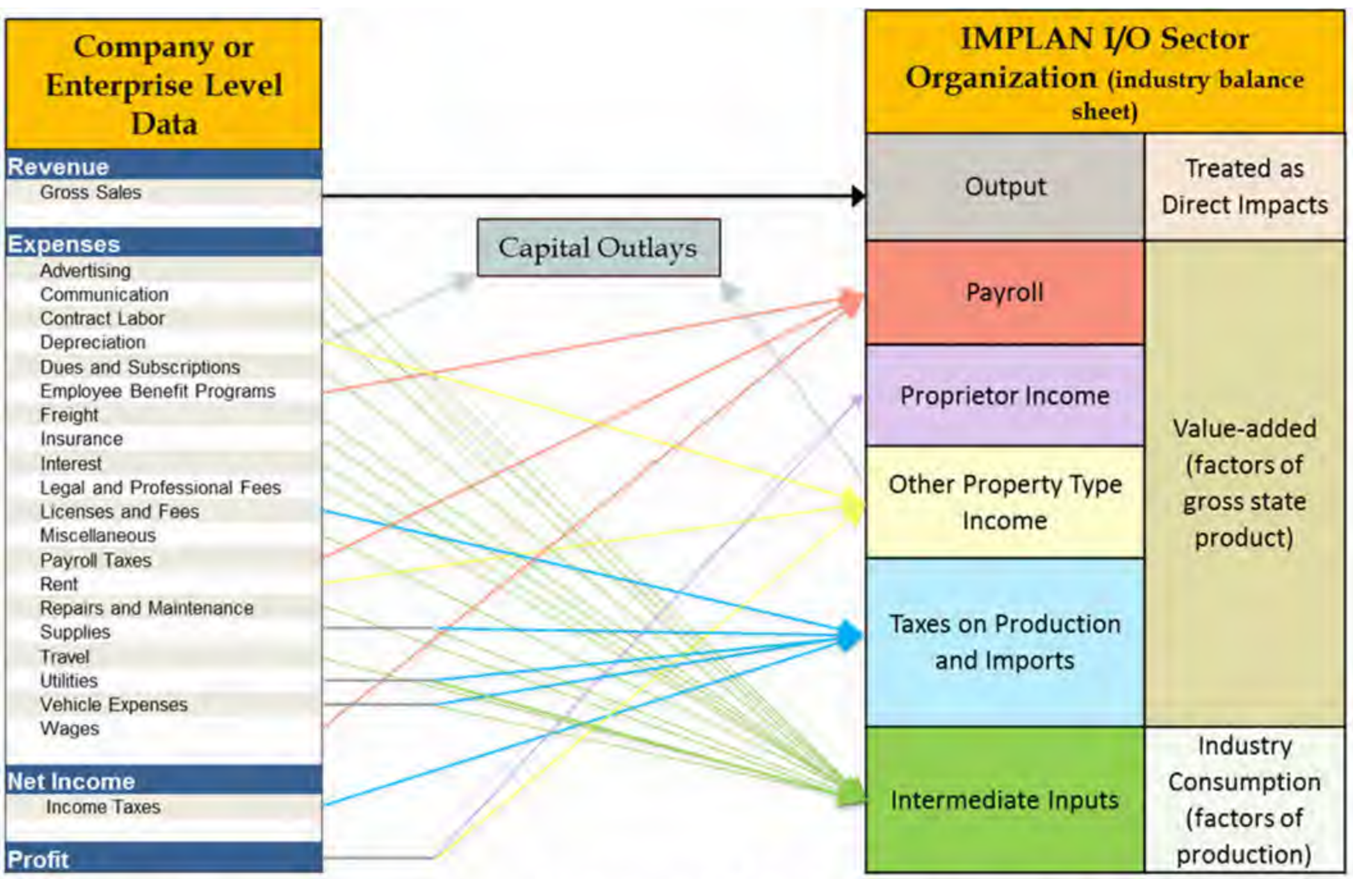
Employment is broadly measured in two distinct categories: covered and uncovered. Covered workers are those that are employed by a business, institution, or government agency, receive a wage or salary, and are subject to unemployment insurance (UI). Jobs that fall under an UI program are called 'covered' employment. Quarterly Census of Employment and Wages (QCEW) employment reported by Job Service North Dakota is 'covered' employment. QCEW data are collected for each state and reported by the U.S. Bureau of Labor Statistics (BLS). Therefore, employment statistics for self-employed individual cannot be derived from QCEW data.



Developing Economic Sector Profiles

An industry balance sheet or economic profile is one of the most important elements in economic contribution studies. Nearly all key economic metrics have their origin within an industry's economic profile/sector. Information and data to create economic sector profiles were collected from surveys of industry firms and data from government agencies.

While the IMPLAN modeling platform provides baseline economic profiles generated from proprietary estimation techniques applied to government data, this study relied on state-sourced data and industry input to create a customized IO matrix. The process of developing study-specific economic profiles and then modifying an IO matrix is time consuming and requires considerable empirical analysis, but the results from those efforts produce a credible and transparent evaluation of an industry's role in an economy.



General Transposition of Financial Information into IMPLAN Economic Sector Profiles

Source: DA Bangsund, Department of Agribusiness and Applied Economics, NDSU

Treatment of Traditional Economic Sectors Supporting Lignite Energy Industry

This summary omits specific details of how the secondary economic effects are distributed among the state's numerous economic sectors and sub-sectors. Several economic sectors support the lignite energy industry by providing inputs and services to various segments of the industry. Examples include manufacturing, financial institutions, legal representation, business services, industrial equipment and machinery, among others. Under some definitions, those activities and sectors are presented as "direct" segments of the industry. However, from the perspective of how this study's input-output analysis was structured, those sectors represent "indirect" economic output of the industry, meaning those sectors are supported and sustained from purchases relating to lignite energy industry mining, conversion, and transportation/distribution.

Acknowledgments

Special thanks are extended to Jason Bohrer, President, Lignite Energy Council, for his leadership, guidance, and information throughout the study, and to Kay LaCoe, Vice President of Communications, Lignite Energy Council who assisted with the surveys and soliciting industry cooperation for the study.

The study authors and study sponsors would like to thank all the companies and individuals that took the time to complete and return the survey materials. This study, with its reliance on industry data, would not have been possible without industry cooperation.

Financial support was provided by the North Dakota Lignite Energy Council. We express our appreciation for their support.

We wish to thank Edie Nelson, Department of Agribusiness and Applied Economics, for document preparation.

EXHIBIT 19

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

STATE OF WEST VIRGINIA, STATE OF INDIANA, STATE OF ALABAMA, STATE OF ALASKA, STATE OF ARKANSAS, STATE OF FLORIDA, STATE OF GEORGIA, STATE OF IDAHO, STATE OF IOWA, COMMONWEALTH OF KENTUCKY, STATE OF LOUISIANA, STATE OF MISSISSIPPI, STATE OF MISSOURI, STATE OF MONTANA, STATE OF NEBRASKA, STATE OF NEW HAMPSHIRE, STATE OF NORTH DAKOTA, 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, and MICHAEL S. REGAN, Administrator, United States Environmental Protection Agency, *Respondents*.	Case No. 24-1120

DECLARATION OF JULIE FEDORCHAK IN SUPPORT OF PETITIONERS' MOTION TO STAY FINAL RULE

I, Julie Fedorchak, 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 Julie Fedorchak, and my business address is 600 E. Boulevard Dept 408, Bismarck, ND 58505. 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 one of three commissioners on the North Dakota Public Service Commission (NDPSC) since 2013. I am currently President of the National Association of Regulatory Utility Commissioners (NARUC), the state's liaison to the Midwest Independent System Operator (MISO), and on the advisory board of the Electric Power Research Institute. I have previously served in numerous leadership roles including President of the Organization of MISO States (MISO), vice-chair of the NARUC Gas Committee, and vice president of the Gas Technology Institute's advisory board.

3. The NDPSC is a state agency created under the Constitution of North Dakota and is vested with, among other things, jurisdiction for the economic regulation of electric and gas public utilities, telecommunication, the siting of energy plants and electric and natural gas transmission facilities, reclamation of active and abandoned mine lands, and railroad safety. The Commission also actively participates in the governance of the Midcontinent Independent System Operator ("MISO") through the Organization of MISO States ("OMS") and the Regional State Committee ("RSC") for the Southwest Power Pool ("SPP").

4. The NDPSC is responsible for ensuring safe, affordable, and reliable electric and gas services for North Dakota ratepayers. It oversees the orderly development of capital-intensive infrastructure of investor-owned utilities within the state, including generation resource planning. Furthermore, the NDPSC serves as the siting authority for energy generation, gas processing, and pipeline and electric transmission within the state.

5. 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 9, 2024, entitled "New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule," 89 Fed. Reg. 39,798 (Final Rule).

6. The NDPSC has consistently highlighted risks associated with the transition from traditional thermal generation and has serious concerns that the Final Rule will further undermine reliability of the power grid. I recently highlighted our concerns to Congress and FERC, expressing the critical need to extend the lives of existing thermal resources to allow time for new technology to "bridge the gap" between "reliability attributes of wind and solar megawatts versus thermal megawatts."[1] If the purpose is to navigate a clean energy transition, it will take patience — not the hasty path created by the Final Rule.

7. The NDPSC is not alone in its reliability concerns. FERC, NERC, and entities charged with overseeing the reliability of our power grids all around the country have been shouting warnings about the long-term reliability of our nation's power grids for anyone willing to listen. 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.[2]

---

[1] *See Pathways to Lowering Energy Prices: Hearing Before S. Comm. on Energy & Nat. Res.*, 117th Cong. (July 13, 2022) (testimony of Comm'r J. Fedorchak, Chair, N.D. Pub. Serv. Comm'n). AD23-9 Annual Reliability Technical Conference, Tr. at 239: 1 (Nov. 9, 2023) (Comm'r Fedorchak). <https://www.energy.senate.gov/services/files/E565FF3C-3B1B-42CD-A4C0-68ED082CC280>. *See also* AD23-9 Annual Reliability Technical Conference, Tr. at 239: 1 (Nov. 9, 2023) (Comm'r Fedorchak).

[2] 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).

Impact of the Final Rule on North Dakota's Power Plants and Power Grids

8. In its 2023 *Long Term Reliability Assessment* NERC highlighted that rising electric demand, coupled with potential for higher generator retirements, will create serious reliability risks over the next ten years.[3] This assessment did not incorporate the cascade of retirements and loss of capacity that would result from the Final Rule. The reliability risks will be prevalent in both Regional Transmission Organizations servicing North Dakota customers.

9. In its *2023 Long Term Reliability Assessment*, NERC identified that the SPP region will be at an "elevated risk" of shortfall in extreme conditions — such as the winter storms that have been recently experienced. This risk is more prevalent when high demand coincides with low wind or above-normal generator outages.[4] As recent as this past January, North Dakota experienced record-breaking cold temperatures during which SPP declared extended cold weather and conservation operation advisories. Concurrently, the weather prevented many generators from running. The combination resulted in multiple severe reliability emergencies.

10. NERC has identified risk in MISO, projecting a "high risk" level indicating insufficient resource adequacy for areas.[5] 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 trended up in installed capacity, accredited capacity to meet system needs

---

[3] North American Electric Reliability Corporation, *2023 Long-Term Reliability Assessment*, 10-11 (Dec. 2023), *available at* https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2023.pdf.
[4] *Id.* at 8.
[5] *Id.*

is moving in the opposite direction. MISO's recent accreditation reforms around direct loss of load have shown that this trend is likely to worsen.[6]

11. MISO, in a recent report on grid reliability has sounded the alarm on the challenges facing the region on grid reliability:

> 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 longduration battery storage, small modular reactors and hydrogen systems may someday offer solutions to this issue, they are not yet viable at grid scale.[7]

12. To underscore our concerns, the loss of a single thermal plant could be the difference between a stable grid and load shedding or brownouts. During Winter Storms Uri and Elliott, Coal Creek Station, a unit capable of dispatching 1,150 MW of power into the MISO market operated at max capacity during both winter storms. This resulted in a higher nameplate capacity rating going into future auctions due to Coal Creek's value in maintaining reliability. An impact on this generator alone has the potential for an immediate and significant impact on MISO North Region and North Dakota customers.

13. The forced, premature retirement of dispatchable fossil fuel generation in North Dakota will increase reliance on intermittent resources (e.g., wind and solar). As reliance on

---

[6] 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

[7] MISO, *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.

intermittent resources is increased, it will result in a downward trend in accredited capacity value for these resources.

14. Regional Transmission Organizations, Public Service Commissions, and similar entities all around the country have been warning that projected increases in intermittent generation sources will not be able to offset the reliability concerns that come with forcing the retirement of dispatchable generation sources.

15. MISO recently reiterated that warning in its "MISO Region Reliability Imperative" report:

> Wind resources can experience "fuel" availability challenges in the form of highly variable wind speeds. Consequently, the energy output of wind can fluctuate significantly on a day-to-day and even an hour-by-hour basis — including multi-day periods when output drops far below average.
>
> For example, over 60 consecutive days in January-February 2020, hourly wind output in MISO averaged more than 8,000 MW. However, … for 40 consecutive hours in the middle of that 60-day block, average hourly wind output dropped to less than 47 MW, and only once exceeded 200 MW in any single hour.
>
> An even longer and broader "wind drought" occurred during Winter Storm Uri in 2021 when the MISO, Southwest Power Pool, Electric Reliability Council of Texas and PJM regions all experienced 12 consecutive days of low wind output.[8]

16. In short, the forced retirement of reliable, dispatchable power generation sources has already significantly threatened the reliability of the power grids that provide electricity to the people of North Dakota, especially during severe weather events. Implementation of the Final Rule will foreseeably make an already precarious situation even worse.

17. North Dakota currently operates 10 lignite coal-fired generating units with a combined capacity of over 4 GW. The Commission is not aware that any of these coal-fired generating units have a plan to retire the unit prior to 2039 and fall into "long term"

---

[8] MISO, *MISO's Response to the Reliability Imperative*, at 11.

requirements. As a result, these plants would require 90 percent capture of CO2 with an associated degree of emission limitation of an 88.4 percent reduction in emissions rate.[9] CCS must be implemented by 2032. If the operating horizon of these coal-fired generating units is lowered to the intermediate range, compliance options offered by the EPA are: (1) Reducing CO2 rate by 16% by 2030 presumptively through co-firing 40% natural gas, and then retiring by 2039, or (2) installing carbon capture and sequestration by 2032.[10]

18. The EPA expects most units to cease operating by 2032 if they do not follow one of these two pathways.[11] Otter Tail estimates that the natural gas pipeline alone for the Coyote Station in North Dakota would cost $153,720,000 to achieve co-firing with natural gas. This doesn't include costs to install and calibrate the natural gas burners or upgrades to equipment that would be needed if it is even feasible to cofire at this location. There is no certainty that there is enough gas supply to achieve this either. The retirement of base load electricity generation capacity with remaining useful life will increase the cost of electricity for North Dakotan ratepayers.

19. As with all increases in the cost of electricity, the most significant impact will be on low-income North Dakotans, as high energy prices operate similar to a regressive tax. But the impact of increased prices of electricity will be felt by all North Dakotans, who will have no choice but to purchase needed electricity at higher rates. For most people, electricity is a requirement of modern life, it is not a luxury that can be set aside if federal rules cause the price to increase dramatically.

---

[9] 40 C.F.R. § 60.5775b(c)(1).
[10] *Id.* § 60.5775b(c)(2).
[11] EPA Proposed NSPS and Emissions Guidelines for GHGs from Power Plants, 88 Fed. Reg. 33,240, 33,245 (May 23, 2023).

20. Indeed, to the extent that the Final Rule creates disruptions in electricity reliability—brownouts or blackouts—the Final Rule will have far reaching direct, indirect, and tertiary impacts throughout the State.

21. Any changes to the electricity generation portfolio caused by implementation of the Final Rule will be immediate, irreversible, and will likely impact North Dakotans for decades, even if the Final Rule is overturned in litigation.

Impact of the Final Rule on the NDPSC Directly

22. NDPSC has already expended significant resources to review the November 2021 proposal, review the December 2022 supplemental proposal, and review the Final Rule to assess the impacts the Final Rule will have on the people of North Dakota.

23. The Final Rule recklessly interjects the EPA into areas traditionally reserved for states, FERC, and ISOs. State utility commissions have traditionally had a reserved authority to establish their own energy and environmental policies, including the authority to determine their own preferred generation mixes, as long as they do not interfere with wholesale markets.[12] This rule mutes the NDPSC's careful consideration of utility investments and vested role in ensuring the orderly development of generation and transmission infrastructure within North Dakota.[13]

---

[12] *See, e.g.*, *Hughes v. Talen Energy Mktg., LLC*, 570 U.S. 150, 154 (2016) ("The States' reserved authority includes control over in-state 'facilities used for the generation of electric energy.'" (quoting 16 U.S.C. § 824(b)(1)) (citing *Pac. Gas & Elec. Co. v. State Energy Res. Conserv. & Dev. Comm'n*, 461 U.S. 190, 205 (1983) ("Need for new power facilities, their economic feasibility, and rates and services, are areas that have been characteristically governed by the States.")); *id.* at 166 ("Nothing in this opinion should be read to foreclose Maryland and other States from encouraging production of new or clean generation through measures "untethered to a generator's wholesale market participation." … So long as a State does not condition payment of funds on capacity clearing the auction, the State's program would not suffer from the fatal defect that renders Maryland's program unacceptable.").

[13] *See, e.g.*, *Hughes*, 578 U.S. at 166; *accord, e.g.*, *PPL EnergyPlus, LLC v. Solomon*, 766 F.3d 241, 255 (3d Cir. 2014) ("The states may select the type of generation to be built—wind or solar, gas or coal—and where to build the facility[,] [o]r states may elect to build no electric generation facilities at all."); *PPL EnergyPlus, LLC v. Nazarian*, 753 F.3d 467, 478-80 (2014); *N.J. Bd. of Pub. Utils. v. FERC*, 744 F.3d 74, 97 (3d Cir. 2014)

24. Unless the Final Rule is stayed, NDPSC will be forced to immediately expend time and resources helping the North Dakota Department of Environmental Quality (NDDEQ), prepare the State of North Dakota's plan for implementing the Final Rule.

25. Absent a stay, NDPSC will need to immediately begin incurring expenses for one of the duties expressly reserved to the States under 111(d) of the CAA—determining the "remaining useful life and other factors" for State power generation facilities. It will also trigger multiple rate proceedings, prudency, siting, accounting determinations, and integrated resource planning.

26. In order to make those determinations for power generation facilities in North Dakota, NDPSC anticipates that it will need to dedicate a minimum of 2,700 hours of staff time and over two million dollars in the upcoming years.

27. Every hour of state staff time and every dollar of state resources expended attempting to comply with the Final Rule cannot be reclaimed; once spent they are gone.

28. Any changes—even minor changes—made to the Final Rule as a result of this litigation will require new studies and modeling to be conducted. This means that all resources expended analyzing the Final Rule will have been wasted, and North Dakota will be unable to recover them.

<u>The Final Rule's Mandate for Additional CCS Permitting Is Simply Not Realistic.</u>

29. The Final Rule assumes that approximately 60,000 miles of CO2 pipelines can be sited, built, and operational around the country in seven years, taking captured carbon dioxide from power plants in locations without suitable underground geology for storing massive

amounts of CO2 and transporting it to places (like North Dakota) that do have suitable underground geology. NDPSC's experience shows that assumption is absurd.

30. As a state that is pioneering the development in CCS, NDPSC has significant experience with the challenges presented by large-scale CO2 transmission siting. Even in a largely rural state, public buy-in remains difficult for these projects. The NDPSC is currently processing an application for a major, multi-state CO2 transmission line for sequestration in North Dakota. After two years, it has yet to receive a single state siting permit.[14]

31. EPA's Final Rule grossly overestimates the speed and ease with which it can be expected to occur.

* * * * *

32. In summary, NDPSC has significant concerns with implementation of the Final Rule that cannot be overstated. The Final Rule's assumptions regarding the installation and operation of nearly 60,000 new miles of CO2 pipeline in seven years are detached from anything approaching what would be realistic or feasible. And if the Final Rule is not stayed while the legal challenges against it proceed, there will foreseeably be serious and irreparable harms to the State and people of North Dakota. Not only will NDPSC be forced to immediately incur significant implementation costs trying to comply with the Final Rule, but North Dakota power plants will likely be forced to retire, the reliability of the grids servicing North Dakota will be significantly threatened, and North Dakota ratepayers will have to pay more for electricity when the grid isn't down.

---

[14] Midwest Carbon Express CO2 Pipeline Project, Case No. PU-22-391. https://apps.psc.nd.gov/webapps/cases/pscasedetail?getId=22&getId2=391#.

33. NDPSC strongly encourages the Court to stay implementation of the Final Rule.

Executed in Bismarck, North Dakota, on May 13, 2024.

Julie Fedorchak

Julie Fedorchak
Commissioner
North Dakota Public Service Commission

EXHIBIT 20

DECLARATION OF STACY TSCHIDER

1. My name is Stacy Tschider. I am the Chief Executive Officer (CEO) for Rainbow Energy Center, LLC ("Rainbow") and Nexus Line, LLC ("Nexus Line"). As CEO, I oversee and direct all aspects of operations and development at Rainbow and Nexus Line. Nexus Line is a 436-mile-high voltage direct current transmission system that runs from Underwood, North Dakota to Dickinson, Minnesota. Rainbow is the owner and operator of Coal Creek Station, a 1,151 MW coal-fired power plant, and participates in the Midcontinent Independent System Operator ("MISO") electricity market. This Declaration is based on my personal knowledge as CEO and analyses conducted by my colleagues.

2. I am submitting this Declaration on behalf of Rainbow in support of Petitioner's motion to stay the rule promulgated on April 25, 2024 by the U.S. Environmental Protection Agency ("EPA" or "Agency") and officially published in the *Federal Register*, titled "New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule" ("Final Rule").

3. The Final Rule theoretically presents two ways for Rainbow to comply. First, Rainbow could install carbon capture and sequestration ("CCS") by 2032.

Second, Rainbow instead could fully convert Coal Creek Station into a natural gas plant that no longer could burn coal by January 1, 2030. Either way, such timelines assume that every step of the process encounters zero delays. Such seamless transition would be unlikely for a project of significant scope demanded by this Final Rule, which has numerous components that range from necessary feasibility studies, permitting, to actual construction in an area already struggling with labor shortages.

4. Absent a judicial stay, Rainbow's ability to comply with the rule within the allotted timeframe is uncertain and that uncertainty inflicts immediate significant harm by chilling Rainbow's ability to generate revenue *now*. As a business that primarily relies on long-term power purchase agreements to recover its investment costs, end-use power customers are already questioning whether Coal Creek Station could continue to operate past 2032 under the compliance timelines set by the Final Rule. The perception of uncertainty alone risks having consumers shy away from contracting with Rainbow. Business opportunities that Rainbow loses now, inflict harm for decades as the required contracts are for 10- to 20-year terms.

5. Additionally, forcing a compressed regulatory timeline for CCS sends the perverse message that companies should skip or shortcut various due diligence measures to meet the deadline set under the Final Rule. Foregoing key studies would impose significant operational risks that Rainbow cannot afford and will not take on. EPA should not force companies to choose between compliance and safety.

RAINBOW AND COAL CREEK STATION

Rainbow and Coal Creek Station's Operations

6. Rainbow is an electric power company headquartered in Bismarck, North Dakota. Rainbow has owned and operated Coal Creek Station since May 1, 2022.

7. Coal Creek Station has been generating and distributing energy in North Dakota and the upper Midwest region of the United States since 1979. Coal Creek Station produces up to 1,151 megawatts of electricity per hour by combusting over seven million tons of beneficiated lignite (coal originally purchased from Falkirk Mining Company which then gets beneficiated in-house with a patented pollution control technology, "DryFining™," further described below). It directly employs over 200 people at its facility near Underwood, North Dakota.

8. Since it began its commercial operation in 1979, Coal Creek Station has continuously improved its methods for controlling air pollution. Coal Creek Station stands out from other coal-fired power plants that it has been acknowledged by the federal government multiple times for its environmental stewardship.[1]

9. As just one example, the Department of Energy ("DOE") selected Coal Creek Station to participate in a government-industry partnership, where Coal Creek

---

[1] *See, e.g.*, 76 Fed. Reg. 58,570, 58,584 (Sept. 21, 2011) (discussing Coal Creek Station's involvement in the Clean Coal Power Initiative).

Station "will help U.S. coal-fired electricity generating plants to meet both existing environmental objectives as well as those emerging in the near future."[2] The resultant multi-pollutant control technology, "DryFining™," improves the heating value of the coal while removing constituents that cause harmful pollution, mainly nitrogen oxide (NOx) and sulfur dioxide (SO_2). This technology is the first of its kind and remains a pioneering technology in the industry.

Rainbow and Coal Creek Station's Commitment to CCS

10. In fact, as EPA notes in the Final Rule, Rainbow has been developing plans to install CCS equipment to capture and permanently sequester the carbon dioxide (CO_2) emitted from Coal Creek Station. Rainbow plans to permanently sequester the captured CO_2 into suitable geological formations located within nearby land. Rainbow has been actively pursuing CCS at Coal Creek Station ever since Rainbow purchased the plant in 2022.

11. With an estimated annual CO_2 capture rate of 8.5 million metric tons, Coal Creek Station's CCS facility would be a multi-billion-dollar investment that would become one of the largest CCS projects in the world.

12. The U.S. Congressional Budget Office ("CBO") estimates that CCS projects for power generation (and other industrial processes) cost between $50 and

---

[2] National Energy Technology Laboratory, Topical Report No. 27, at 4 (June 2012) (provided as Attachment A to this Declaration).

\$120 per ton of CO_2,[3] which means CCS operations for Coal Creek Station would cost at minimum \$1.164 million every day (\$50 times 8.5 million, divided by 365). And while such figure is the publicly available proxy, it is likely that the CBO study did not account for post-Covid inflation, borrowing costs, amortization periods (and the resultant payback period), and the life cycle of the plant—making the realistic cost estimate even higher.

13. From a planning perspective, CCS project costs would include construction of the carbon capture facility, balance of plant equipment at Coal Creek Station, and CO_2 pipelines and injection well infrastructure. Such components would include engineering, leasing activities, permitting, procurement, transportation, technical advisory and commissioning supervision, commercial expense, contingency fees, general and administrative expenses, chemicals, license fees, construction, and commissioning.

14. Rainbow must also consider operation and maintenance costs. These would include, for example, staff costs, annual maintenance, insurance, taxes, chemical consumption, waste disposal, and electricity.

15. Rainbow has completed its initial front-end engineering design study ("FEED study") with the Energy & Environmental Research Center at the University

[3] CBO, *Carbon Capture and Storage in the United States* (Dec. 2023), https://www.cbo.gov/publication/59832.

of North Dakota ("EERC"), the state's leading expert on CCS. The FEED study, co-funded by Rainbow and the North Dakota Industrial Commission, cost over $16 million, and is now being followed with a separate bridge study to optimize the process design.

16. The storage area is being studied for suitability as a CO_2 storage facility under a $47 million DOE grant (titled "CarbonSafe"), the study being led by EERC and supported by Neset Consulting. But while DOE's CarbonSafe grant supports the *planning* for the storage part of CCS (developing a plan for a CO_2 storage facility), Rainbow has not secured DOE funding for either the storage infrastructure or the "capture" part of Rainbow's CCS project.

17. And at this time, the Section 45Q tax credit for carbon sequestration under the Inflation Reduction Act would be inadequate. To start, the direct pay option under the tax credit provides little value due to the timing of the cash receipt (which could take up to 18 months in payment); with a project of this scale, the cash flow could not properly service the debt obligations. Additionally, the tax credit has not kept pace with inflation and supply chain constraints, and the stipulations attached (such as compliance with the prevailing wage and apprenticeship program) further increase costs. These cost constraints would only increase as every other fossil fuel-fired power plant moves to comply with the Final Rule, as demand for workforce and equipment would concurrently surge.

18. To summarize, Rainbow's CCS project would be a multibillion-dollar investment. Government subsidies (such as DOE grants and tax credits) only alleviate some of the projected costs to the investment. Moreover, in Rainbow's experience, participation in government grants slows the project timeline because of the additional regulatory approval requirements and the time it takes for the release of funds. It is uncertain, and in fact made *less* likely by the existence of the Rule, that other means of defraying the necessary costs could be found in time to comply with this rule. The Final Rule's compressed timelines and lack of flexibility create a barrier to the installation of the very technology it claims to promote.

MERCHANT GENERATION AND THE POWER MARKET

19. Investment costs, such as those affiliated with CCS or other emission control methods, present unique challenges to Rainbow due to Rainbow's particular status and role as a "merchant power producer" in the power/electricity market.

Traditional Electric Utility Structures

20. By way of background, customers in many parts of the United States consume electricity provided by either investor-owned utilities or public utilities (which, for purposes of this discussion, include municipal utilities and public utility districts). Both of these utilities operate under a vertically integrated monopoly framework. The utility company owns the generation and transmission necessary to

serve its end-use customers, manages the system operations to serve its customers, and is the only entity that provides the electric distribution and supply.

21. Because of their vertically integrated monopoly structure, these utilities are also heavily regulated by the government to ensure that the interests of the consumers are preserved. Typically, the state's energy/utility commission would be the entity regulating the utility's operation from generation to distribution and end-use sale of power (whereas the federal government, through the Federal Energy Regulatory Commission, would regulate interstate transmission).

22. Such regulatory measure includes rate-setting. Through a rate-setting order, the state energy/utility commission would dictate the rate (i.e., electricity price) the utilities could charge to their end-user consumers.

23. The flip side of this process is that the state commission sets the rates at a level so that the regulated utility could cover its cost of service plus a reasonable "rate of return" (profit) on the capital the utility invested on its plants, whether that be the original construction or improvements to the facility. Setting the rate at a guaranteed rate of return ensures that these power plants are built in the first place, and that utilities have an incentive to invest and in turn improve their services to the end-use consumers.

24. In other words, investor-owned utilities and public utilities may be able to recover the costs for installing CCS (if their state regulators approve); they would redirect their costs by charging an increased rate to the end-use consumers.

The Merchant Power Producer

25. In contrast to what has been discussed above, Rainbow (through Coal Creek Station) is a privately owned "merchant power producer." Rainbow is not an investor-owned utility, nor is it a public utility. Unlike the traditional structure of many utility companies, Rainbow does not have a vertically integrated monopoly system where it controls everything from electricity generation all the way to distribution of power to the end-use consumers who, often times, could not switch electricity providers. Instead, merchant power producers would sell all the generated power into the wholesale open market.

26. Rainbow's unique status as a merchant power producer has two significant implications for the Final Rule. First, Rainbow has no "captive ratepayer." While investor-owned utilities and public utilities have a set customer base (similar to how normal household consumers cannot select/switch their utility company), Rainbow has none. Rainbow does not have a monopoly over its end-use consumers; the market (and its participants) could always favor a different electricity producer if Rainbow's power production costs are too high.

27. Second, unlike investor-owned utilities and public utilities which have a chartered right—guaranteed by the state government—to recover costs (usually through rate-setting orders as discussed above), Rainbow cannot recover any capital or operational costs from its end-use customers. Rainbow has no "rate base," i.e., the right to earn a specified rate of return backed by the state energy commission, and never will as a merchant power producer.

28. Because merchant power producers cannot pass on their costs to end-use customers, Rainbow can recover its capital or operational costs—such as the cost of installing and running CCS—in only two ways.

29. First, Rainbow could enter into power purchase agreements with customers at a set price negotiated at the time of the contract. Rainbow currently has eight operative power purchase agreements with various end-use power customers in the upper Midwest and is likely to execute at least three more by mid-May of 2024.

30. Rainbow enters into both "energy agreements" and "capacity agreements." That is—Rainbow currently has both (1) power purchase agreements which specify how much electricity Rainbow will generate and transmit to the point of sale (energy agreement), ranging anywhere from 50 to 350 MWh, and (2) power purchase agreements which specify how much electricity Rainbow guarantees it will

generate or supply if requested on the spot to make sure peak demand is met (capacity agreement), ranging anywhere from 10/kW-month to 350/kW-month.

31. Second, Rainbow could sell power at a wholesale level to the regional transmission organization market, which in Rainbow's case would be MISO. Of note, this market is also heavily influenced by the federal government with subsidies that deflate prices to low rates.

32. Here, Coal Creek Station provides approximately 1,050 MWs of "seasonal capacity" to the MISO market. MISO needs such dispatchable generation (providing power on demand) so that electricity reliability is preserved during the various seasons, including summer and winter when electricity demand is higher.

33. In both strategies, since merchant power producers lack monopoly status in the electricity open market, Rainbow is more vulnerable to market conditions and the needs/demands raised by the end-use consumers. One of the key concerns created by the Final Rule that already has been raised by a potential customer is whether Coal Creek Station can provide power in the long term given the risk it might be unable to comply with the regulatory deadlines. This, in turn, risks disruption (at worst, cessation) in Coal Creek Station's operations.

CONTROL REQUIREMENTS UNDER THE FINAL RULE

34. The Final Rule sets aggressive compliance timelines for a considerable infrastructure project. This raises serious risks that Coal Creek Station could not

complete its project, whether that be installation of CCS or full conversion into a natural gas plant. Perhaps even more harmful in the near term, the tight regulatory timeline sends a *market signal* to potential customers of Coal Creek Station's power that, when they consider or negotiate any contracts, they must seriously account for the possibility of Coal Creek Station's operational disruption for failure to comply with the Final Rule.

Compliance Deadlines

35. Coal Creek Station is an existing coal-fired power plant that intends to operate past January 1, 2039. Accordingly, it can maintain its ability to operate only if it meets one of the two compliance requirements.

36. First, pursuant to Section 60.5775b(c)(1)(i) of the Final Rule, Coal Creek Station could install CCS equipment and capture and permanently sequester 90% of the CO_2 emitted by January 1, 2032.

37. Second, pursuant to Section 60.5880b of the Final Rule and further supported in the preamble to the Final Rule, Coal Creek Station could fully convert into a gas-powered unit that no longer retains the capability to fire coal after December 31, 2029.

38. Either of those deadlines could be extended by up to one year under Section 60.5740b(a)(11) of the Final Rule. At the same time, the extension request

must demonstrate (with documented information) that the owner/operator cannot comply due to circumstances beyond their control.

39. Theoretically speaking, the state plans regulating emissions of existing sources may account for the plant's "remaining useful life and other factors" (commonly referenced as "RULOF") to either loosen the compliance requirements (such as a less stringent best system of emission reduction and relatedly a less strict emissions limit) or adopt a longer compliance schedule. However, the preamble to the Final Rule indicated that RULOF accommodations would only be available when there are "fundamental" differences between the power plant's unique circumstances and the information EPA considered in determining the applicable emissions limit or the compliance schedule. Even if RULOF is invoked, "the particularized compliance obligations must differ as little as possible." Therefore, it would be unlikely that the state plan approved by EPA would relax the compliance deadline significantly.

40. For the following reasons, Rainbow faces serious concerns as to whether it could meet either compliance deadline (even accounting for any extension).

Timeline Complications for CCS

41. Rainbow is about two years into its CCS project since it recently completed its initial FEED study. Notwithstanding this head start, Rainbow still faces significant concerns about meeting its compliance deadlines.

42. All CCS projects, including what Rainbow plans, require many years of development, engineering, testing, permitting, and construction to become a reality. Because CCS has not yet been widely adopted by the industry, the technology is at a high risk of exceeding the planning execution schedules.

43. To illustrate in general terms, a bridge study (following the FEED study) for 6 months, a permit preparation and application for 6 months, an agency's review of the permit for 2 years following submission, and construction of the carbon capture facility for 5 years already would put the project at 8 years from the date of this declaration (i.e., project completion in 2032) for carbon capture *without* storage.

44. Separately, Rainbow must conduct a storage characterization study for 18 months, develop a storage plan for 2 years, and undergo a 2.5-year storage permitting process to have storage certainty prior to constructing the carbon capture plant. In that same timeframe, Rainbow would also need to construct the storage facilities.

45. All the above timeline assumes the best-case scenario, where funding has been fully obtained, and the plant will encounter zero unexpected regulatory or

construction delays. Complications that Rainbow has already experienced refute the optimistic projection that no delays will occur. As one example, the FEED study itself was originally intended to be completed by October 2023; yet the study was extended to March 2024 due to the addition of scope to further examine redundancy. And following the substantial completion of the FEED study, Rainbow must undergo a bridge study to further examine the risk of long-term amine degradation (in which the substance capturing CO_2 would degrade), optimization of the process design, and the cost estimates produced in the FEED study to look for opportunities to improve the business case for CCS. By way of reference, Project Tundra, one of the CCS projects EPA has referenced to demonstrate feasibility, also had to do more than one FEED study that caused significant delays in project completion.

46. As another example of unexpected delays, Rainbow has been seeking a permanent geological sequestration site for the CO_2 in the land near Coal Creek Station. In that process, the collection of critical 3D seismic data—originally planned for the winter of 2023/2024—got pushed back to the winter of 2024/2025 due to delays in federal regulatory approvals (required only due to Rainbow's participation in DOE's CarbonSafe grant program) and uncharacteristically warm weather. Of note, because of construction schedules and engineering requirements, these foundational studies and permit procurement (for both capture and storage) could not be conducted concurrently.

47. The above two incidents are delays that were completely unplanned when Rainbow was developing and executing its own CCS project timeline. As with any large infrastructure project, additional sources of unexpected delays could arise at any moment during project development.

48. For example, during the construction and engineering phase labor shortages could occur, especially given that Coal Creek Station is in a remote location in North Dakota. Alternatively, since the Final Rule forces all coal-fired steam generating units and newly constructed stationary combustion turbines to install CCS around the same time, multiple plants will be competing against each other for the same labor and equipment resources to meet the same deadline of January 1, 2032.

49. Ironically, the compressed regulatory timeline under the Final Rule itself could also be a source of CCS project delays. This is because when it confronts the potential risk of being unable to comply with the Final Rule, now Rainbow must undergo a separate "business case" study to assess whether proceeding with a CCS project (or any other facility improvement project) would make economic sense compared with shutting the plant down or fully converting to a natural gas plant. Similarly, Rainbow must now also reassure investors that proceeding with CCS is a viable investment strategy that Rainbow could recover through its operation as a merchant power producer. In simpler terms, preparing the business case and securing

funding for CCS takes even more time now that CCS projects must proceed under a set regulatory deadline or else face significant non-compliance consequences.

50. Finally, since Rainbow is still in the process of evaluating securing additional government funding for its CCS project, it must account for the time it would take for the government to review and approve such grants. For example, DOE funding could be stipulated on certifying compliance with the National Environmental Policy Act, a review process that is well known to take significant time.

51. All the above scenarios of unforeseen complications (pertaining both to unexpected delays already occurred and to realistic scenarios for project delays given the scope of Coal Creek Station's CCS project) directly refute EPA's position that CCS is feasible under the Final Rule's timeline. While EPA has cited two examples, Project Tundra and Petra Nova, as the basis to determine CCS by 2032 is feasible, the former has not been executed yet, and the latter took approximately seven years and $195 million in DOE funding, only for the project to still not meet the 90% CO_2 sequestration rate expected under the Final Rule.

52. Additionally, while EPA also referenced Rainbow's CCS project webpage as a basis to determine that CCS is the best system of emission reduction, this webpage was published in 2022, the same year that the original FEED study for CCS began. But since then, the rate of inflation has far outpaced any of the tax

benefits provided by the 45Q tax credit. Long lead times and increased pricing for specialized technical equipment also increased the expected capital expenses (and in turn, projected timeline) compared to the original projection made in Rainbow's webpage. And as already discussed, additional studies to evaluate CCS's economic feasibility had to be conducted. EPA's representation of a feasible CCS timeline based on Rainbow's webpage has been refuted by previous delays and required revisions to project timeline estimates.

Timeline Complications for Conversion to Natural Gas

53. The timeline for Coal Creek Station to fully convert to a steam generating plant that exclusively fires natural gas and cannot fire coal is likewise too short. Whether such conversion is even possible to begin with is unlikely due to *other* environmental concerns with such a project. And even if it were, a conversion by 2030—2 years sooner than the CCS compliance pathway—appears infeasible.

54. To start, the challenges Coal Creek Station must go through for a CCS project—initial feasibility studies, permitting, materials procurement, and actual construction and/or retrofitting—would apply to the natural gas conversion project as well. Likewise, the conversion project would encounter the same funding problem, where Rainbow must assess the business case for the project, potentially convince outside investors that Coal Creek Station is a profitable investment that will survive, and go through regulatory procedures (e.g., compliance certifications).

And unlike CCS projects, tax incentives would not exist for a natural gas conversion project, presenting a separate cost recovery challenge.

55. The overall supply (and resultant) price of natural gas could also inflict uncertainty if demand increases at such a dramatic price. As other facilities evaluate these same compliance options, availability of natural gas could decrease dramatically, in turn increasing cost while reducing supply. The intrinsic volatility of natural prices could impact the ability to make a feasible business case for conversion of Coal Creek Station.

56. Coal Creek Station faces an additional challenge in that natural gas is not a readily accessible resource in the area. Even if the facility itself could convert to a natural gas-firing plant, Coal Creek Station must also build a pipeline that spans greater than 50 miles just to access the nearest natural gas reserve. Even more challenging, the nearest natural gas reserve is across the Missouri River, so part of the pipeline must be built under a body of water. This requires significant additional environmental assessments and permitting.

57. Before any pipeline project could even start, Rainbow must engage in route and landowner participation. Based on Rainbow's experience, negotiations to obtain and eventually record the proper easements from landowners (potentially purchases) would already take years to complete. Landowner fatigue and Not In My Back Yard ("NIMBY") sentiments have been a significant problem for decades to

the point that the North Dakota State Legislature needed to pass a pipeline restoration and reclamation oversight program in the 64th Legislative Session in 2015 to address ongoing concerns from landowners as it related to developing pipelines on their property.

58. Only then would it make sense for Rainbow to obtain the permits, of which a cross-river natural gas pipeline project would require many. Listing just two for purposes of this Declaration, Rainbow would need to seek a transmission facility permit and a pipeline safety permit from the North Dakota Public Service Commission. This does not even account for the fact that, since the pipeline must be built under a river, additional studies would need to be conducted to make sure that the surrounding ecosystem is not disrupted or that there is no unauthorized discharge under the Clean Water Act. For example, Rainbow may also need to obtain a Section 404 Clean Water Act permit if the pipeline project is expected to discharge dredge or fill materials into the water.

59. Again, a best-case scenario where the construction timeline encounters zero labor shortages, zero public pushback, and zero material-procurement chokeholds would mean the constructing a pipeline of such length *on land* could be completed in 4 to 5 years. But a natural gas pipeline construction of this nature also risks vocal, heated public opposition, and the general constituents' aversion to construction projects of this kind. For example, like with the Dakota Access

Pipeline, one anti-pipeline protest gone wrong or one sour public relations event could mean the entire project gets mired in lawsuits or regulatory hearings, which could add a year or two of additional delay. Worse, the complications discussed above are magnified by the fact that the pipe must cross a river.

60. Indeed, EPA's representation that constructing these natural gas pipelines will be easy starts from the wrong premise. EPA's preamble to the Final Rule discusses how it would be "reasonable to assume that most plant owners would develop sufficient pipeline capacity to deliver the maximum amount of desired gas use in any moment." Far from such representation being accurate here, Coal Creek Station never seriously considered pipeline capacity planning because the plant is far away from an accessible natural gas reserve, because natural gas prices are intrinsically volatile, and because contractually the plant has been bound to operate exclusively on the lignite mined nearby for the life of the plant.

61. Rather, Rainbow would be required to cease the CCS investments it already engaged in, conduct an internal study to assess whether 100% natural gas conversion would be the proper course of action, and then go through the requisite timeline (along with all the challenges and delays referenced above) that deviates significantly from what EPA expects.

RAINBOW'S IMMEDIATE, IRREPARABLE HARMS

62. Absent a judicial stay, Rainbow would be harmed in the next 2 years primarily for 2 reasons. First, Rainbow will incur significant business opportunity losses; with the Final Rule currently in place, Rainbow is already experiencing significant challenges in (re-)negotiating its long-term power purchase agreements. Second, and relatedly, Rainbow will lose broad swaths of on-site generation opportunities specifically relating to data centers that need power purchase agreements now but are withholding because Coal Creek Station's future is uncertain.

Rainbow's Power Purchase Agreements

63. As explained previously, Rainbow's power purchase agreements have largely been successful. Under these power purchase agreements, Rainbow will provide power from Coal Creek Station to various end-use power customers located throughout the upper Midwest for at least seven more years.

64. The last power purchase agreement terminates in May 2031.

65. Rainbow expects that general demand for additional power purchase agreements will only increase, including long-term power purchase agreements that may extend into 2032 and beyond. For example, Rainbow has observed significant market interest in Rainbow's generation for the next 10 to 15 years from other end-use consumers.

66. But given that these power purchase agreements are long-term commitments to provide and receive electricity at a set price, the certainty of a power plant's longitudinal operability is essential. To illustrate, it makes less sense for an electricity consumer to enter into a 15-year power purchase agreement with Coal Creek Station if the consumer knows Coal Creek Station risks operation disruption/cessation around year 8 (2032) due to CCS non-compliance, or mid-way through the contract.

67. With the introduction of the Final Rule, Rainbow is already experiencing customer and potential-customer pushback even though these entities are greatly interested in Rainbow's power generation. Rainbow is already receiving customer inquiries as to whether Coal Creek Station could meet the Final Rule's 2032 compliance deadline. In another scenario, Rainbow is already receiving inquiries where customers and potential customers are asking if the original long-term agreements that had been under discussion should be shortened, with the service to terminate prior to 2032.

68. In other words, the Final Rule is fundamentally disrupting Rainbow's business and the ability for Rainbow to sell its product in the open market; such disruptions will be ongoing and are irreparable because lost customers would be locked into *long term* contracts with other providers. Rainbow's bargaining position has been, and will continue to be, severely weakened. As one illustration, due to the

regulatory uncertainty created under the Final Rule, Rainbow would be forced to ask for "contingency" or "out" provisions where it could terminate or exit the agreement if Coal Creek Station must cease operations for not meeting CCS deadlines. Naturally, such provisions would decrease Rainbow's bargaining leverage—potentially conceding on price, perhaps even eliminating Rainbow from consideration by the current and potential customers.

69. Such disruptions are significant to how Rainbow runs its business, both in the short term and the long term. Currently about 60% of the electricity sold by Rainbow is through power purchase agreements that go up to 2031. Accounting for the 2 additional opportunities Rainbow is close to executing, that share goes up to 67%. At minimum, the Final Rule risks slashing Rainbow's electricity sales by half because Rainbow simply could not enter into power purchase agreements in which the terms of service would go past 2032.

70. To be clear, the *current perception* that power purchase agreement customers (and potential customers) have on Rainbow's compliance feasibility would be essential because the long-term agreements are under negotiation in the present. If these entities decide to execute long-term power purchase agreements with other electricity generators, whether Rainbow gains regulatory certainty two years later becomes irrelevant. After all, these agreements are 10- to 15-year terms.

This means that Rainbow cannot secure those contracts back for the next decade or so; it would be a 15-year economic loss that must be accounted for now.

Rainbow's Loss of On-Site Generation Customers

71. Similar to the forfeiture of long-term power purchase agreements, Rainbow would equally lose the opportunity to pursue on-site generation opportunities with potential customers. Electricity consumers have been reaching out to Rainbow so that, instead of going through the MISO wholesale market, Coal Creek Station could directly provide electricity service.

72. Specifically, Rainbow is in the process of negotiating power contracts with data centers and cryptocurrency mining facilities, which consume significant amounts of electricity for an extended period.

73. These data center entities are seeking 20-year contracts where Rainbow could provide certain amounts of power in 5-year increments. For now, negotiations are ongoing where the data centers subscribe to 40 to 200 MWs of direct electricity service; but eventually, the amount of power under discussion would significantly exceed 200 MWs.

74. However, these long-term contract opportunities are similarly under jeopardy by the Final Rule. Either data centers would be disinclined to enter into a power purchase agreement that they perceive will be cut short due to risk of non-compliance with the Final Rule, or the terms of the agreement would be condensed,

and Rainbow would forego the opportunity to sell the much more significant volumes of electricity that would be guaranteed later.

75. Since these data centers and cryptocurrency mining facilities are making their investments now, they must execute their power purchase agreements soon so they can have their facilities running. Absent a judicial stay, Rainbow's ability to capitalize on these opportunities would be foregone.

CONCLUSION

76. For the reasons described above, Rainbow is facing imminent and substantial harm by the Final Rule.

I, Stacy Tschider, declare under penalty of perjury that the foregoing is true and correct.

Executed on May 8, 2024,

Stacy L. Tschider
Chief Executive Officer

Attachment A

to the Declaration of Stacy Tschider

National Energy Technology Laboratory, Topical Report No. 27

Published in June 2012

TOPICAL REPORT NUMBER 27 JUNE 2012

CLEAN COAL TECHNOLOGY

Clean Coal Power Initiative Round 1 Demonstration Projects

Applying Advanced Technologies to Lower Emissions and Improve Efficiency

685a

A report on three projects conducted under separate cooperative agreements between the U.S. Department of Energy and:

- Great River Energy
- NeuCo. , Inc.
- WeEnergies

Cover Photos:

- Top left: Great River Energy's Coal Creek Station
- Top right: We Energy's Presque Isle Power Plant
- Bottom: Dynegy's Baldwin Energy Complex

CLEAN COAL TECHNOLOGY

Clean Coal Power Initiative Round 1 Demonstration Projects

Executive Summary

Coal is both plentiful and affordable in the United States (U.S.) and is expected to maintain its nearly 50 percent share of total electricity generation as demand increases. Our nation's energy security and environmental management depend on the resolution of environmental concerns associated with increased coal use. Cost-effective and efficient technologies developed to ensure the environmentally clean utilization of this resource have been designated as "clean coal technologies."

Clean coal technology research and development (R&D) began in the 1970s. Many promising technologies had emerged by the 1980s, but were not implemented at the commercial scale due to the financial and technical risks associated with the first commercial-scale installation. A pathway to facilitate the further development of these technologies was initiated by Congress and implemented by the U.S. Department of Energy (DOE) in 1985 with the creation of the Clean Coal Technology Demonstration Program (CCTDP). The CCTDP forged cost-sharing partnerships between DOE, non-federal public entities, technology suppliers, and clean coal technology stakeholders to reduce the financial and technical risks preventing their commercial-scale implementation and demonstration.

Building on the successes of CCTDP, DOE implemented the Power Plant Improvement Initiative (PPII) in 2001 to focus on enhancing the reliability of the nation's power grid. PPII was followed by the Clean Coal Power Initiative (CCPI) in 2002.

The CCPI is an industry/government cost-shared partnership program that furthers efficient clean coal technologies for use in new and existing U.S. electric power generating facilities. CCPI is a technology demonstration program implemented through a series of solicitations (rounds) that target priority areas of interest to meet DOE's Roadmap goals. Technologies emerging from the program will help U.S. coal-fired electricity generating plants to meet both existing environmental objectives as well as those emerging in the near future. CCPI is planned and managed by the DOE Office of Fossil Energy (FE) and implemented by the National Energy Technology Laboratory (NETL).

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." CCPI Round 2 (CCPI-2) encouraged proposals to demonstrate advances in coal gasification systems, technologies that permit improved management of carbon emissions, and advancements that reduce mercury (Hg) and other power plant emissions. CCPI Round 3 (CCPI-3) required projects that could demonstrate the capture, recovery, and sequestration or beneficial use of carbon dioxide (CO_2) from coal-fired power plants.

Future CCPI rounds will build upon the successes of previous rounds, demonstrating advanced technologies that strengthen the nation's energy and economic security with minimal impacts to the environment and consumer.

This report describes three projects that have successfully demonstrated emissions and plant control system upgrades that support the CCPI-1 objective of ensuring that the U.S. has clean, reliable, and affordable electricity. The Baldwin Energy Complex project utilized an artificial intelligence (AI) system that increases the plant's thermal efficiency while reducing emissions. The Great River Energy (GRE) project increased boiler efficiency by reducing the fuel moisture content. The TOXECON™ project removed Hg from the flue gas stream without affecting the marketability of the fly ash.

The **Demonstration of Integrated Optimization Software at the Baldwin Energy Complex** project demonstrated the integration of advanced, on-line, combustion/emission control optimization software. The demonstration showed that an integrated process optimization approach can increase the thermal efficiency and reliability of the plant, with the concurrent benefit of a corresponding reduction of airborne emissions such as nitrogen oxides (NO_X), CO_2, and particulates.

The Cooperative Agreement for the project at the Baldwin Energy Complex was awarded on February 18, 2004. The project duration was 45 months and was completed on November 17, 2007. The project cost was \$19,094,733 with a DOE share of \$8,592,630 (45 percent). Project goals were met with the exception of the heat rate improvement target. However, it is believed that the heat rate goal could have been met had plant personnel not placed a higher priority on cyclone flame stability and NO_X reduction. To date, the participant has reported well over 50 sales of its optimization modules.

In GRE's **Increasing Power Plant Efficiency: Lignite Fuel Enhancement** project, waste heat from a power plant was used to lower the moisture content of the lignite fuel it consumes. Reducing the moisture content of the lignite increases the energy efficiency of the boiler, which means less fuel is required for a given load. Emissions reductions were achieved as a result of increased fuel quality, segregation of iron sulfide (pyrite) and mercury in the drying process, and increased oxidation of mercury resulting in greater mercury removal in the flue gas desulfurization (FGD) system.

A Cooperative Agreement for the Lignite Fuel Enhancement project was awarded on July 9, 2004. The project duration was 69 months with an operations completion date of March 2010. The estimated project costs were $31,512,215 with a DOE share of $13,518,737 (43 percent). The moisture content of the coal was reduced by the target amount of 8.5 percent, which resulted in a higher heating value (HHV) improvement from 6290 British thermal units/pound (Btu/lb) to 7043 Btu/lb. Also, the moisture removal process and the resulting increased fuel quality resulted in mercury (Hg) emissions being reduced by 41 percent, with NO_X and sulfur dioxide (SO_2) reduced by 32 and 54 percent, respectively. GRE has reported that 120 organizations have signed the necessary secrecy agreements to obtain detailed information on the technology. Some studies have been carried out to evaluate the technology for specific applications.

The **TOXECON™ Retrofit for Mercury and Multi-Pollutant Control on Three 90 MW Coal-Fired Boilers** project (TOXECON™) was an integrated Hg, particulate matter, SO_2, and NO_X emissions control demonstration program for application on coal-fired power generation systems. The TOXECON™ process utilized sorbents that were injected into a pulse-jet baghouse to control emissions. The technology was configured to not affect fly ash quality and its potential to be sold for constructive use. **TOXECON™** has been installed at seven plants in addition to Presque Isle Power Plant (PIPP) and robust sales of the Hg Continuous Emissions Monitor (CEM) have been reported. The recently released new Hg standard is expected to provide additional impetus for future application.

The total project cost was $47,512,830, with DOE providing $23,756,415 (50 percent). The demonstration began operation in January 2006, and was completed in September 2009. The project achieved the emissions reduction goals of 90 percent for Hg and 70 percent for SO_2 individually; however, the concurrent reduction of these emissions through an integrated treatment process was not consistently achieved. All remaining project goals, except for NO_X reduction, were met.

Clean Coal Technology Demonstration Program (CCTDP)

According to the Energy Information Administration's Annual Energy Outlook 2011, the demand for electricity in the United States is projected to increase by 25 percent by the year 2035. Because coal is both plentiful and affordable, the generation of electricity from this abundant resource is expected to continue to account for nearly 50 percent share of total generation. The nation's energy and economic security and environmental quality depend on the resolution of environmental concerns associated with increased coal use. These concerns can be addressed through the development of technology-based solutions that ensure environmentally clean energy utilization. These solutions must be both cost-effective and efficient to support economic growth. This new generation of technologies has been designated as "clean coal technologies."

The R&D of clean coal technologies began in the 1970s, with many promising technologies having emerged by the 1980s. The technologies were, however, unproven in a commercial setting and not implemented due to financial and technical risks. A pathway was needed to prove their technical performance and cost competitiveness in a commercial setting in order to facilitate their acceptance and reduce the risk of implementation. This pathway was initiated by Congress and implemented by the DOE beginning in 1985 with the creation of the Clean Coal Technology Demonstration Program (CCTDP). The CCTDP forged cost-sharing partnerships among the DOE, non-federal public entities, technology suppliers, and other clean coal technology stakeholders to reduce the financial and technical risks preventing the demonstration and commercialization of these technologies. As a condition of participation, CCTDP demonstrations were required to be at a scale and in an operational environment sufficient to determine their potential for satisfying marketplace technical, economic, and environmental needs.

Building on the successes of CCTDP, DOE implemented the Power Plant Improvement Initiative (PPII) in 2001, which called for technologies that could be rapidly implemented to enhance the reliability of the

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.

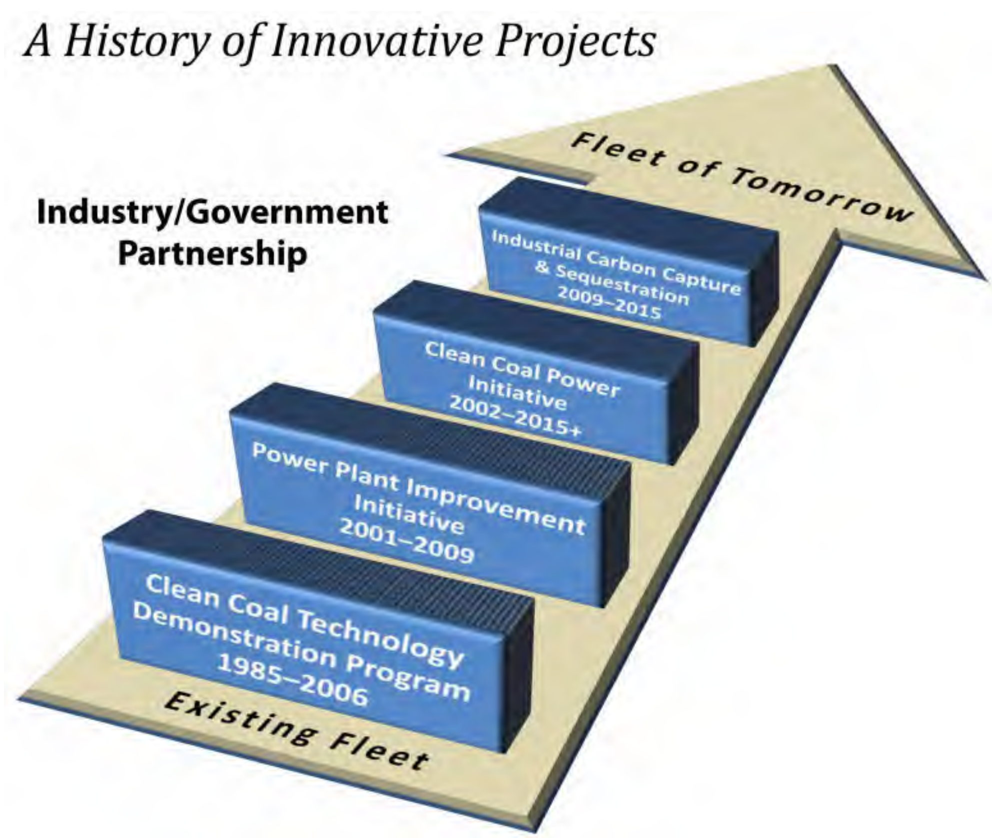
MATS establishes alternative quantitative emission standards, including SO_2 (as a surrogate for HCl). Filterable particulate matter serves as a surrogate for non-mercury air toxic metals, which can also meet a standard based on the total emissions of the eight non-mercury air toxic metals or the plant 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

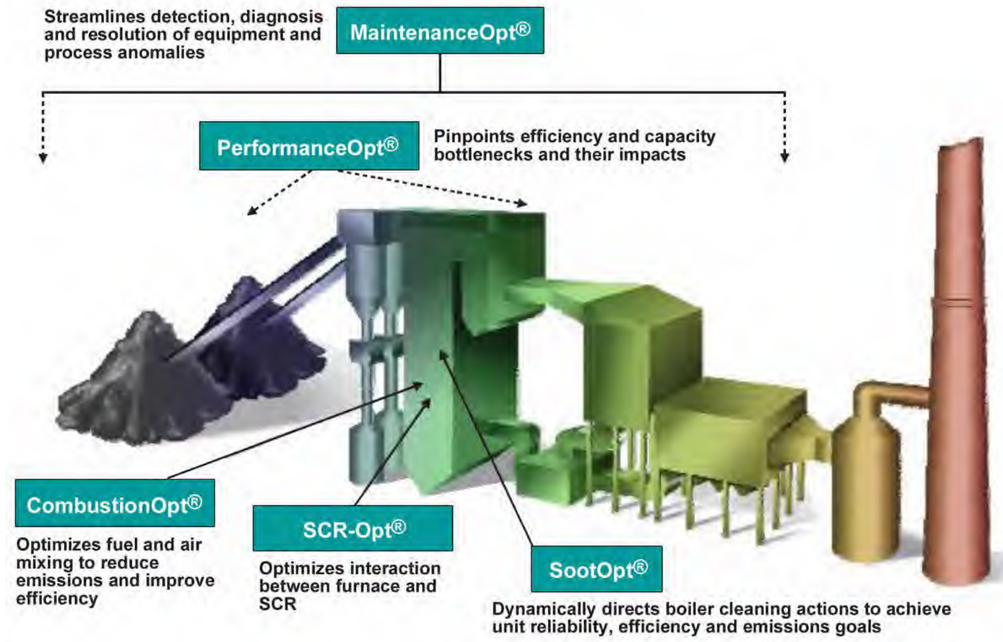
Project objectives were to reduce the BEC NO_x emissions by five percent, increase efficiency by 1.5 percent, and increase net annual electrical power production by 1.5 percent by improving reliability and availability. Additional objectives were to reduce greenhouse gases, Hg, and particulates, and 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.

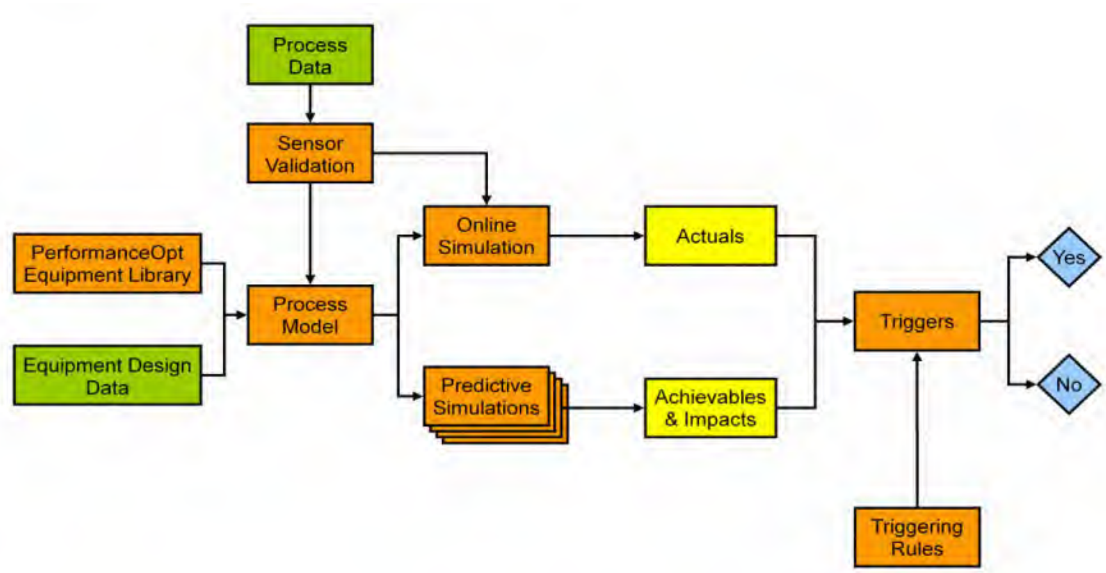
PerformanceOpt

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

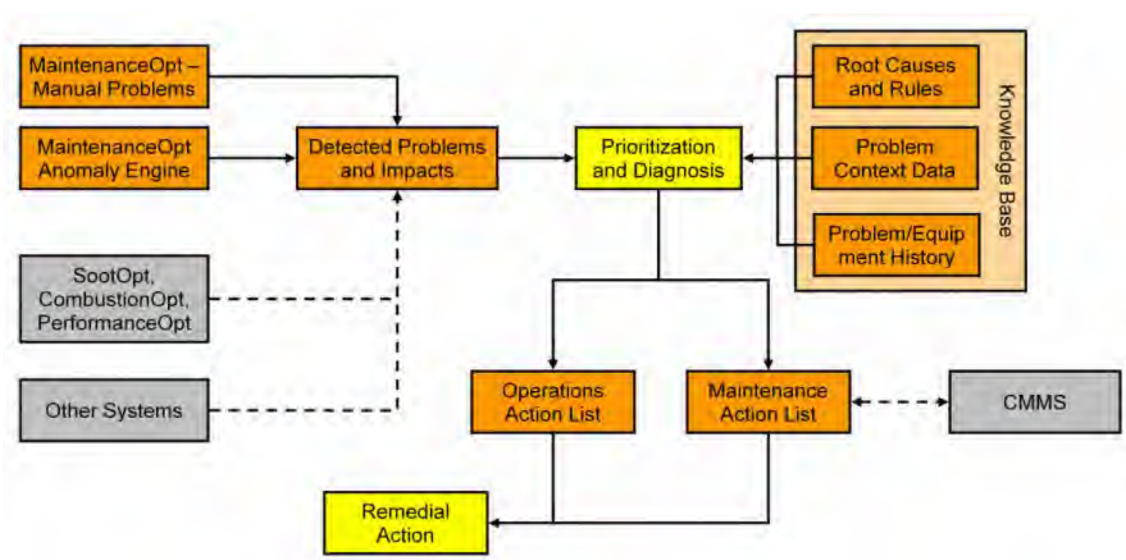
The optimizer modules were developed and refined during the project period. The optimization modules, in concert with NeuCo's proprietary ProcessLink® technology, directly controlled the plant in closed loop mode or advised plant operators of suggested actions in an advisory mode. The results discussed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

- Neural networks, which mimic the capacity of the human brain to handle complex nonlinear relationships and "learn" new relationships in the plant environment.
- Advanced algorithms or expert systems that follow a set of pre-established rules written in code or computer language.
- Fuzzy logic (FL), which involves evaluation of process variables in accordance with approximate relationships that have 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

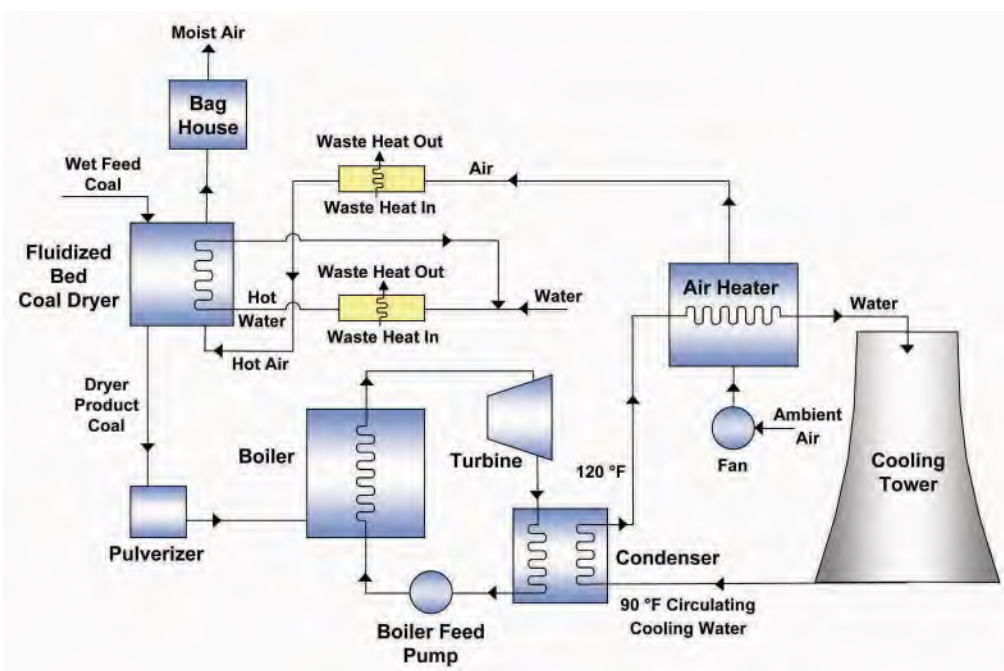
This project has its roots in lignite drying technology R&D conducted by GRE and others since the 1990s. As the R&D work progressed, GRE became convinced of the viability of the lignite drying concept. After identifying a fluidized-bed coal dryer (FBCD) in 2002 as their coal drying technology of choice, 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.

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

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.

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.

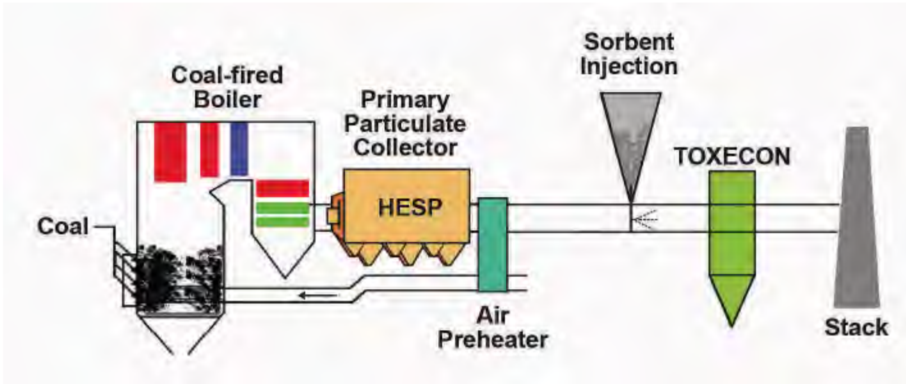
Project Description

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

Printed in the United States on recycled paper

June 2012

EXHIBIT 21

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

STATE OF WEST VIRGINIA, STATE OF INDIANA, STATE OF ALABAMA, STATE OF ALASKA, STATE OF ARKANSAS, STATE OF FLORIDA, STATE OF GEORGIA, STATE OF IDAHO, STATE OF IOWA, COMMONWEALTH OF KENTUCKY, STATE OF LOUISIANA, STATE OF MISSISSIPPI, STATE OF MISSOURI, STATE OF MONTANA, STATE OF NEBRASKA, STATE OF NEW HAMPSHIRE, STATE OF NORTH DAKOTA, 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, and MICHAEL S. REGAN, Administrator, United States Environmental Protection Agency, *Respondents*.	Case No. 24-1120

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 electric 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 the 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 9, 2024, entitled "New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for

Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule," 89 Fed. Reg. 39,798 (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 30% of the electricity generated in North Dakota is exported out of the State through the two Regional Transmission Organizations that service the State—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. And when demand for electricity exceeds the dispatchable supply, the foreseeable result will be blackouts or energy rationing.

EPA's Grid Reliability Assumptions Are Deeply Flawed

10. NDTA commissioned an analysis of EPA's resource adequacy assumptions included in the docket for the Final Rule and a grid reliability study conducted by Always On Energy Research (AOER).[1] An examination of EPA's assumptions reveals a number of issues. First among these issues is EPA's accreditation assumptions, which is the percentage of an energy resource's theoretical capacity that the Agency assumes will actually be available based on factors including weather. For instance, new and existing wind and solar resources receive different accreditations over time—existing resources receive a higher accreditation in the future relative to new resources. This assumption defies common sense, as future resources would be expected to be more efficient than existing resources. The following demonstrates several obvious inconsistencies with accreditation of energy resources in EPA's modeling:[2]

[1] The data in the following paragraphs is from EPA's resource adequacy modeling and is included in the docket for this rulemaking. EPA, Analysis of the Final Greenhouse Gas Standards and Guidelines: Power Sector Modeling, *available at* https://www.epa.gov/power-sector-modeling/analysis-final-greenhouse-gas-standards-and-guidelines. The data may be found in a .zip file, contains a series of spreadsheets representing the output files generated by the Integrated Planning Model (IPM). *Id.* (Final Rule (zip)).

[2] The attributes in the following slides are drawn from the following data from the Final Rule zip file:

EPA Capacity Accreditation: Final Rules SupplyResourceUtilization.xlsx (calculated by dividing the R.M Capacity MW by the Dispatch Capacity MW for each resource by model year)

Reserve Margin: Final Rules SupplyResourceUtilization.xlsx (totaled the capacity in R.M Capacity MW for each resource type by model year)

Total Installed Capacity: Final Rules SupplyResourceUtilization.xlsx (totaled the capacity in Dispatch Capacity MW for each resource type by model year)

EPA Accreditation by Resource Proposed and Final Rules

- EPA continues to use unrealistically high capacity accreditations for:
  - New and existing thermal plants.
  - New and existing wind, solar, and battery storage.
- EPA continues to give new and existing wind and solar resources different accreditations

EPA Accreditation: Proposed vs. Final		
Resource	**Proposed Rule**	**Final Rule**
Existing Wind	19%	14%-20%
Existing Solar	55%	19%-24%
New Wind	9%-25%	8%-23%
New Solar	32%-52%	30%-52%
New and Existing Thermal	100%	100%
Existing Hydro	56%	54%
New Hydro	65%	65%
Existing Energy Storage	48%	94%
Pumped Storage	95%	95%
New Battery Storage	100%	100%

EPA Accreditation for Existing and New Wind and Solar Resources in Final Rule

- EPA continues to give new and existing wind and solar resources different accreditations.
- EPA gives existing wind higher accreditation in later years despite doing the opposite for new wind.

EPA Final Rule Model Year Accreditation for Existing and New Wind and Solar Resources							
Resource	**2028**	**2030**	**2035**	**2040**	**2045**	**2050**	**2055**
Existing Wind	14%	14%	14%	20%	20%	20%	20%
New Wind	16%	23%	15%	10%	9%	9%	8%
Existing Solar	24%	24%	24%	19%	19%	19%	19%
New Solar	39%	50%	52%	40%	34%	33%	30%

11. In addition, EPA's grid capacity assumptions are annual rather than seasonal. This means that EPA simply assumes that intermittent resources will be available at the same rate throughout the year, which we know is not the case. To cite an obvious example, solar energy is higher in the summer than the winter. MISO has developed seasonal capacity assumptions for intermittent resources. Applying these seasonal accreditations to EPA's

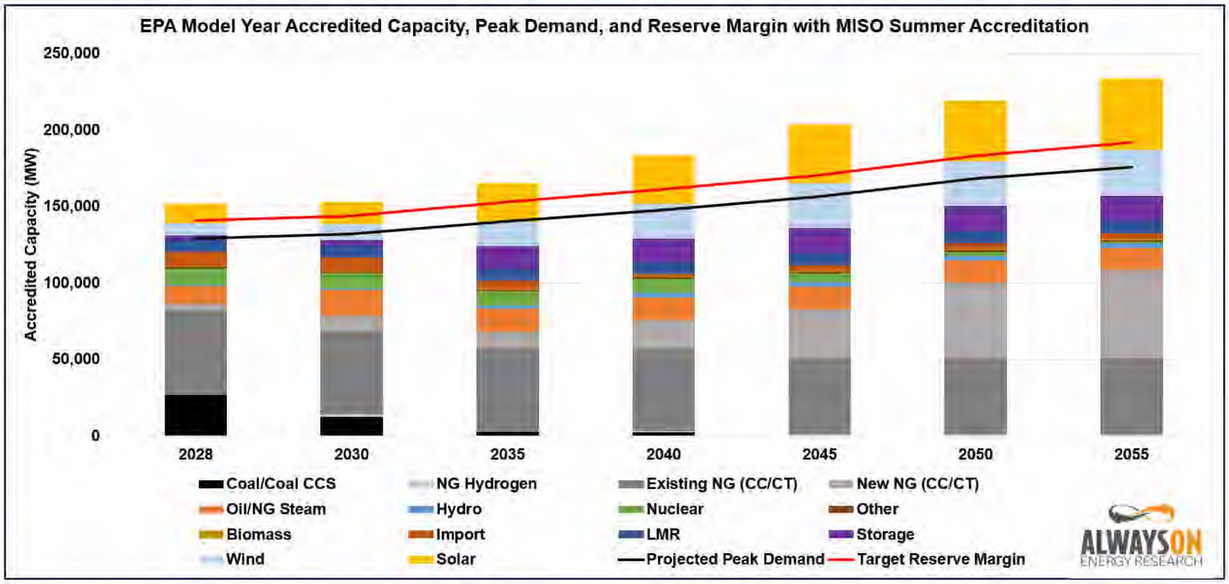
capacity assumptions reveals significant problems in summer and winter. This is because EPA's resource adequacy model for the Final Rule relies on wind, solar, and battery storage to meet projected peak demand in MISO after 2030. This will result in rolling blackouts if wind and solar do not perform at times when they are needed. In the following graphs, note that meeting projected demand (the black line) will require a significant amount of wind energy to be consistently available:[3]

MISO Seasonal Accreditation by Resource

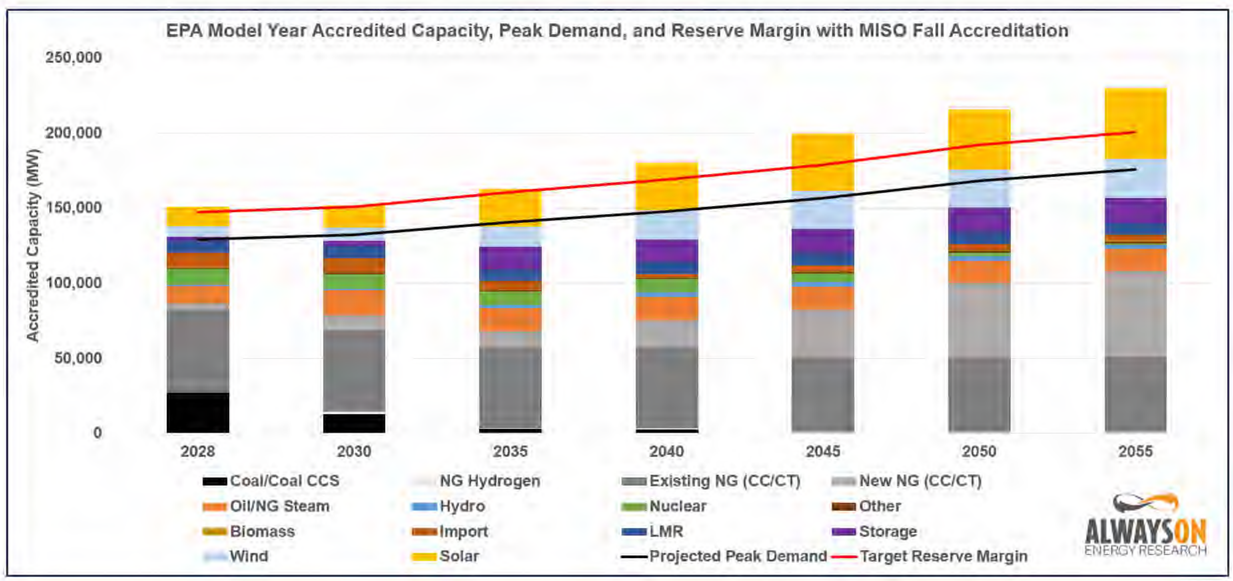
Seasonal Capacity Accreditation in MISO Planning Year 2024-25				
Season	Wind	Solar	Thermal	Target Reserve Margin
Winter	53.1	5	90	27.4
Spring	18	50	90	26.7
Fall	15.6	50	90	14.2
Summer	18.1	50	90	9

[3] MISO, *Planning Resource Auction: Results for Planning Year 2024-25* (Apr. 25, 2024), *available at* https://cdn.misoenergy.org/2024%20PRA%20Results%20Posting%2020240425632665.pdf (providing MISO seasonal accreditation figures). Peak demand forecast is calculated from Final Rules Overview File.xlsx.

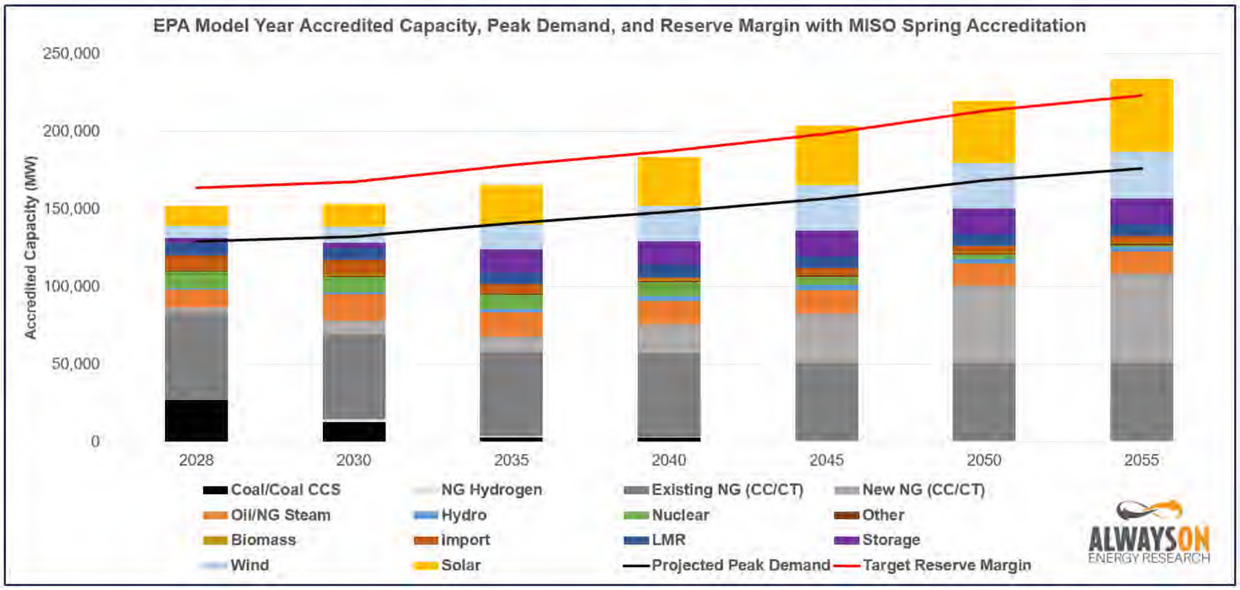
EPA Firm Capacity Using MISO Accreditation in Summer



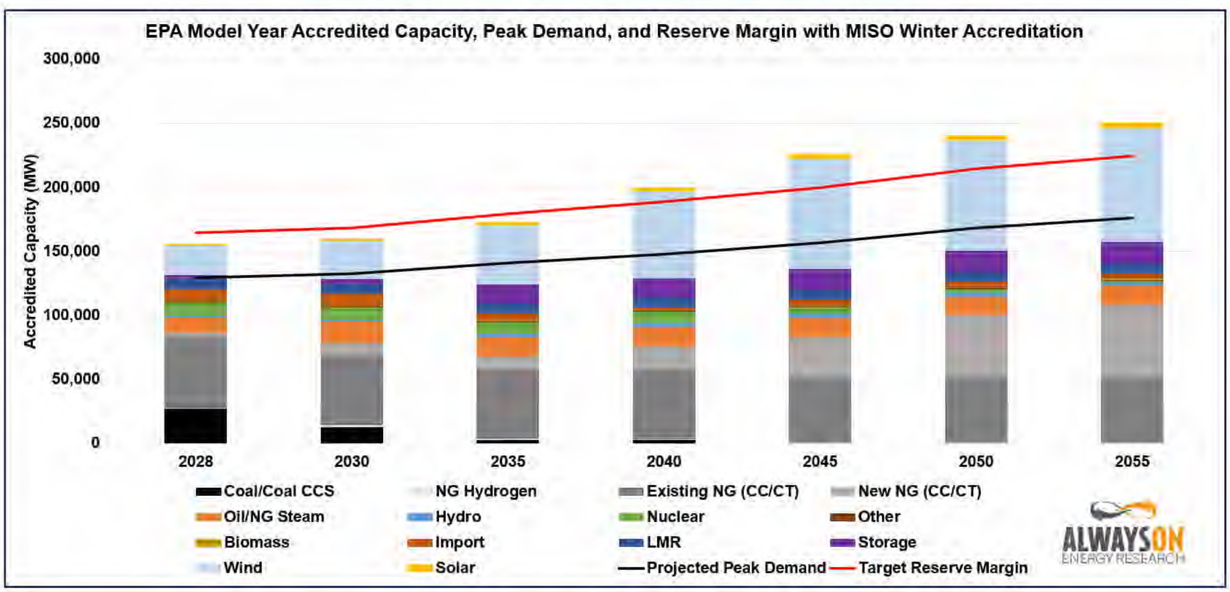
EPA Firm Capacity Using MISO Accreditation in Fall



EPA Accredited Capacity Using MISO Accreditation in Spring

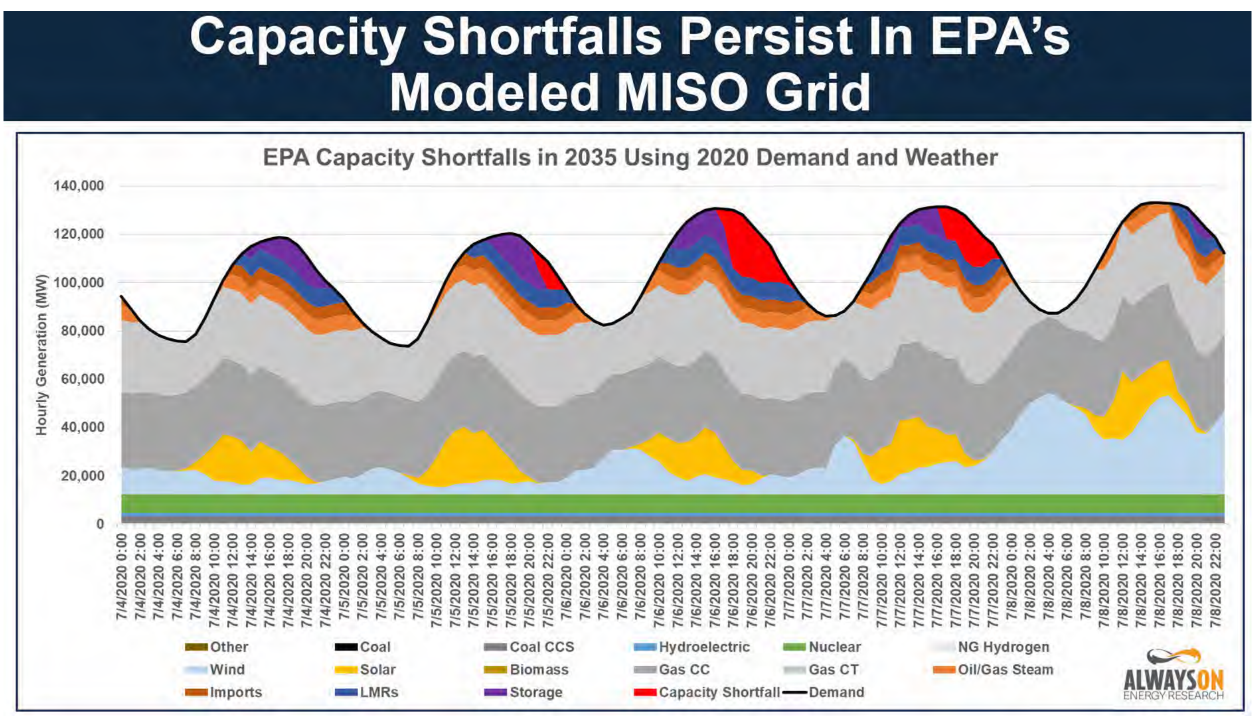


EPA Accredited Capacity Using MISO Accreditation in Winter

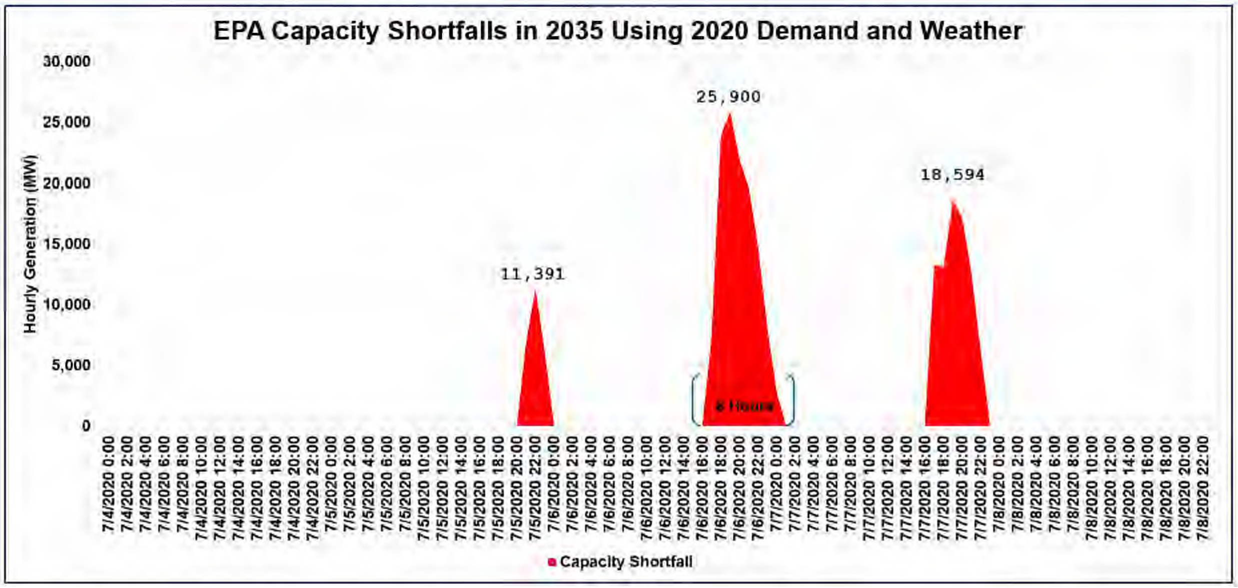


12. In addition to assessing EPA's capacity assumptions, AOER conducted a reliability analysis, which models electricity availability on an hourly basis and includes a range of historical weather scenarios that have actually occurred in the past. The analysis compared

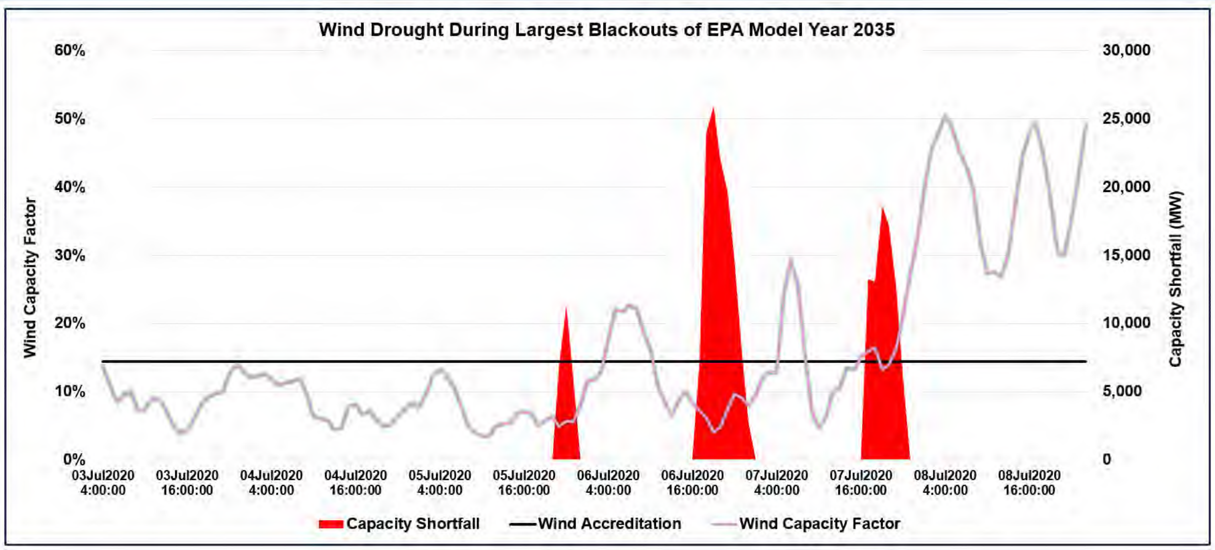
EPA's modeled generation portfolio to the historical capacity factors for wind and solar in 2019, 2020, 2021, 2022, and 2023 to assess whether the installed resources would be able to meet electricity demand for all hours in each of the historic comparison years. AOER made several adjustments that were generous to EPA, such as raising generation characteristics from the historical MISO characteristics to meet EPA's assumptions for peak load, annual generation, and capacity factors. In addition, the analysis replicated EPA's additional reliability mechanisms by allowing greenhouse gas emitting units to run without mitigating emissions to help meet demand during capacity shortfalls and to charge the batteries on the system to reduce the severity of shortfalls. Even still, significant capacity shortfalls persist. The red portion of the graphs shows electricity shortfalls, that is, blackouts. The most significant blackout is modeled to occur in July 2040, when more than 8 million homes would be without power.



EPA Capacity Shortfalls



Wind Capacity Factors During Capacity Shortfalls

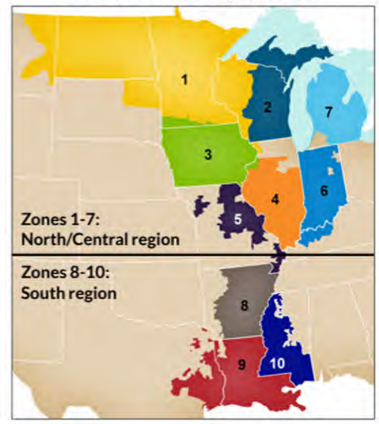


Assessing Severity of the Blackouts

Summer 2024 PRA Results by Zone

	Z1	Z2	Z3	Z4	Z5	Z6	Z7	Z8	Z9	Z10	ERZ	System
PRMR	18,697	13,396	10,787	9,403	8,297	18,565	21,565	8,431	21,888	5,038	N/A	136,067

MISO Resource Adequacy Zones



- The worst capacity shortfall is a 25,900 MW capacity shortfall that would occur in July 2040 using the 2020 HCY.
- For context, this shortfall would account for 19 percent of MISO-wide Planning Reserve Margin Requirement (PRMR) in the 2024 Planning Reserve Auction (PRA).
- This is the nearly the equivalent of MISO Zones 1 and 5 suffering blackouts based on the PRMRs in the PRA.

EPA Total Hours of Shortfalls

Total Hours of Shortfalls							
Year	2028	2030	2035	2040	2045	2050	2055
2019	0	0	10	4	4	2	2
2020	0	2	17	8	6	3	1
2021	0	1	18	0	0	0	0
2022	0	0	0	0	0	0	0
2023	0	1	16	4	1	0	0

EPA Value of Lost Load

MISO is currently seeking to increase its Value of Lost Load (VOLL) estimates to $10,000 per MWh. These values represent the total number of MWhs unserved multiplied by the VOLL in each EPA model year when the modeled portfolio is tested for reliability against hourly wind and solar generation from 2019, 2020, 2021, 2022, and 2023.

Value of Lost Load							
Year	2028	2030	2035	2040	2045	2050	2055
2019	$0	$0	$1,098,884,128	$520,647,875	$394,628,665	$106,598,673	$47,011,180
2020	$0	$30,169,037	$2,292,345,201	$866,401,675	$483,925,493	$90,814,986	$9,343,828
2021	$0	$555,775	$1,297,237,560	$0	$0	$0	$0
2022	$0	$0	$0	$0	$0	$0	$0
2023	$0	$58,796,196	$1,321,887,240	$216,154,963	$49,167,850	$0	$0

The Final Rule Threatens an Already Vulnerable Power Grid

13. 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.

14. Prior to 2016, MISO had no instances requiring the use of emergency procedures, but since then, there have been 48 Maximum Generation events.[4]

15. Since 2022, MISO has been operating near the level of minimum reserve margin requirements.[5]

16. In 2023, both the MISO and SPP grid operators issued warnings about the adequacy of generation resources to meet peak demand situations.[6]

---

[4] 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.

[5] Midcontinent Independent System Operator (MISO), *MISO'S Response to the Reliability Imperative*, at 6 (Feb. 2024), *available at* https://cdn.misoenergy.org/2024%20Reliability%20Imperative%20report%20Feb.%2021%20Final 504018.pdf?v=20240221104216.

[6] MATS Study at 9.

17. 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.[7]

18. 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 should be 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.

19. A graphic from NERC's *2023 Long-Term Reliability Assessment* illustrates the gravity of current projections for our national power grids.[8] Areas in red are at high risk of not having sufficient capacity during normal weather events. Areas in orange are at elevated risk of having capacity short falls in severe weather events.

[7] 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.
[8] *Id.*

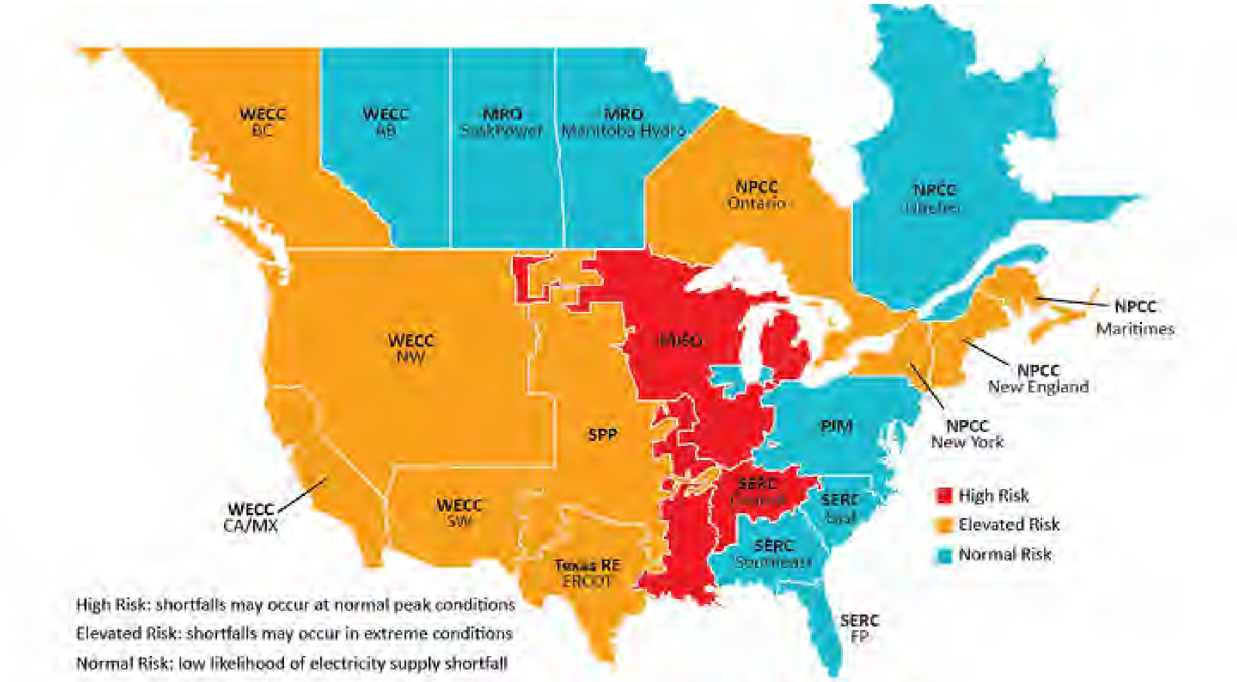


Figure 1: Risk Area Summary 2024–2028[8]

20. On February 26, 2024, MISO released its report titled *MISO's Response to the Reliability Imperative*, which 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 reliability attributes.[9]

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

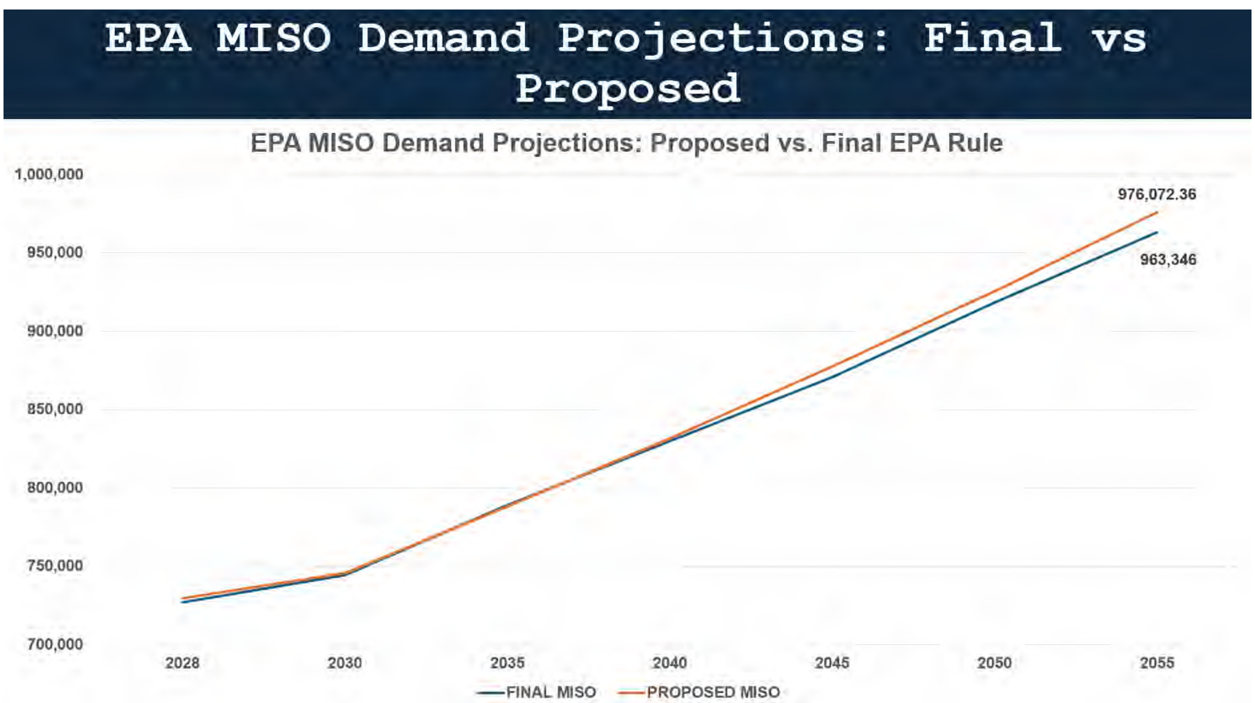
> While MISO is fuel- and technology-neutral, MISO does have a responsibility to inform state and federal regulations that could jeopardize electric reliability. *In the view of MISO, several other grid operators, and numerous utilities and states, the U.S. Environmental Protection Agency (EPA) has issued a number of regulations that could threaten reliability in the MISO region and beyond*.
>
> In May 2023, for example, EPA proposed a rule to regulate carbon emissions from all existing coal plants, certain existing gas plants and all new gas plants. As proposed, the rule would require existing

[9] MISO, *MISO'S Response to the Reliability Imperative*.

coal and gas resources to either retire by certain dates or else retrofit with costly, emerging technologies such as carbon-capture and storage (CCS) or co-firing with low-carbon hydrogen.

MISO and many other industry entities believe that while CCS and hydrogen co-firing technologies show promise, they are not yet viable at grid scale — and there are no assurances they will become available on EPA's optimistic timeline. *If EPA's proposed rule drives coal and gas resources to retire before enough replacement capacity is built with the critical attributes the system needs, grid reliability will be compromised.*[10]

22. The Final Rule fails to properly account for grid strain. EPA has downwardly revised its projected peak demand forecasts in both MISO and SPP relative to the proposed rule. This change is at odds with load growth forecasts throughout the country that are being upwardly revised to accommodate demand growth from data centers, manufacturing facilities, and electrification efforts.



[10] *Id.* at 11-12 (emphasis added).

23. In short, 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. If a reliable power grid is important for meeting the basic needs of modern society, alarm bells need to be going off. And if a reliable power grid is important for meeting the basic needs of modern society, now is not the time to be forcing even more dispatchable sources onto retirement tracks.

24. If the Final Rule forces even more fossil fuel 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.

Executed in Bismarck, North Dakota, on 5/13/2024.

Claire Vigesaa

Claire Vigesaa
Executive Director
North Dakota Transmission Authority

EXHIBIT 22

No. [24-1120]

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

State of West Virginia, et al.,

Petitioners,

v.

Environmental Protection Agency and Michael S. Regan, in his official capacity, as Administrator of the U.S. Environmental Protection Agency

Respondents.

On Petition for Review of Action by the U.S. Environmental Protection Agency

---

DECLARATION OF KENDAL STEGMANN IN SUPPORT OF PETITIONERS' MOTION FOR STAY PENDING REVIEW AND FOR AN ADMINISTRATIVE STAY

I, Kendal Stegmann, hereby declare and state under penalty of perjury that the following is true and correct to the best of my knowledge, based on my personal knowledge and information provided by Oklahoma Department of Environmental Quality personnel:

1. My name is Kendal Stegmann, and my business address is 707 N. Robinson Avenue, Oklahoma City, OK 73102. I am over the age of eighteen, have

personal knowledge of the subject matter and am competent to testify concerning the matters in this declaration.

2. I have served as the Air Quality Division Director of ODEQ since June 2020. I have a history degree and a law degree from the University of Oklahoma. My job responsibilities include overseeing the Oklahoma air quality program, the purpose of which is to protect human health and the environment by maintaining air quality standards, limiting harmful emissions, and providing transparent information to the public about air quality conditions.

Purpose of Declaration

3. I am submitting this declaration in support of Oklahoma's motion to stay the final rule, published by the Environmental Protection Agency (EPA) on May 9, 2024, titled "*New Source Performance Standards for GHG Emissions from New and Reconstructed EGUs; Emission Guidelines for GHG Emissions from Existing EGUs; and Repeal of the Affordable Clean Energy Rule*," 89 Fed. Reg. 39798 (May 9, 2024) (Final Rule). The Final Rule is EPA's final action after publishing the proposed May 2023 carbon dioxide (CO2) emissions standards for fossil fuel-fired EGUs under §111 of the Clean Air Act (88 Fed. Reg, 33240, herein referred to as the Proposal) and reviewing comments on the Proposal from ODEQ and other stakeholders.

State Regulation

4. The mission and vision of ODEQ is to protect and improve public health and our environment and to lead the nation in fostering a healthy and sustainable future through effective and innovative environmental actions.

5. It is ODEQ's responsibility to ensure that the air in Oklahoma meets public health and welfare standards established under the federal Clean Air Act (CAA), including the relevant standards of performance for greenhouse gas (GHG) emissions for electric generating units promulgated by the EPA.

6. The GHG standards within the Final Rule are promulgated by the EPA in 40 CFR Part 60, Subparts TTTT, TTTTa, and UUUUb for new and existing affected sources, respectively, under the CAA.

7. ODEQ promulgates state rules pertaining to air quality standards, develops state implementation plans to meet the federal standards, works to obtain EPA approval of state plan elements, issues construction and operating permits to stationary sources, and ensures compliance with state and federal air quality rules.

8. To date, ODEQ has begun evaluating the Final Rule, including estimating the number of electric-generating units affected by the Final Rule and has begun considering how to incorporate the Final Rule into its existing rules and create a state plan.

9. The Final Rule relies on technological innovations such as carbon capture and storage/sequestration (CCS) that have not yet been demonstrated at

scale. From an energy and policy perspective, ODEQ has seen no evidence that CCS is commercially feasible in the energy sector and at scale, especially considering the timeline EPA is mandating.

10. ODEQ estimates that the Final Rule will affect a total of 30 existing EGUs (10 coal-fired and 20 natural gas-fired steam boilers) in Oklahoma.

a. The 10 coal-fired steam boiler units can be divided into the following subcategories: four fluidized bed units, four tangentially fired units, and two dry bottom wall fired boilers. One of the tangentially fired units (with a nameplate capacity of 473 Megawatts (MW)) is scheduled to retire in 2026. The remaining coal-fired units have no scheduled retirement date and the total nameplate capacity of those units is 3,026 MW. One utility stakeholder has mentioned the possibility of replacing one existing coal-fired unit (with no scheduled retirement date as of yet) with a natural gas-fired combined cycle.

b. The 20 natural gas-fired steam boilers have a total nameplate capacity of 6,059 MW. A permit has been issued recently that would authorize the replacement of two natural gas-fired steam boilers with two simple cycle turbines. None of the remaining natural gas-fired steam boilers have a planned retirement date.

c. The Final Rule is likely to impact the plans to operate these units and may lead to accelerated retirement of many of them. Premature retirement of existing units is likely to increase the risk of power interruptions and may necessitate costly alternative methods of ensuring grid reliability.

11. The Final Rule will affect a number of new units subject to 40 CFR Part 60, Subpart TTTT and TTTTa that have already been permitted or are in the process of being permitted.

12. ODEQ is required to develop a 111(d) State Plan to address the requirements in 40 CFR Part 60, Subpart UUUUb. As part of the development of the State Plan, ODEQ will need to develop state rules in Title 252, Chapter 100 of the Oklahoma Administrative Code (OAC). Rules affecting air quality must go before the Air Quality Advisory Council (AQAC) to be approved. The AQAC holds at least two regular meetings each year. Multiple council meetings are sometimes required before approval is granted. If approved, the rules are then sent to the subsequent Environmental Quality Board meeting for adoption. The adopted rules then go to the next session of the Oklahoma Legislature. The Legislature may approve, reject, or not act on the adopted rules. The Governor then has the ability to affirm or veto the Legislature's actions or take action if none was taken by the Legislature. Based on this rulemaking process, it can take 18 months or more before a rule is effective.

This is just one component of the development of the state plan. It will also require engagement with the affected EGUs. Therefore, it is anticipated that the development of the 111(d) state plan for 40 CFR Part 60, Subpart UUUUb will take longer than three years due to the rulemaking process, requirements for meaningful engagement in 40 CFR Part 60, Subpart Ba, as well as the development of Remaining Useful Life and Other Factors (RULOF) provisions.

13. In order for a state plan to be approvable by EPA, it would almost certainly have to include:

a. The identification of all EGUs and affected units, including emission data;
b. The imposition of emission standards for each affected unit;
c. The establishment of methods to ensure compliance, including schedules for compliance, and identification of all applicable monitoring, recordkeeping, and reporting requirements for each affected unit;
d. A demonstration that each affected unit's emission standard is quantifiable, non-duplicative, permanent, verifiable and enforceable; and
e. Meaningful engagement with stakeholders. Stakeholder engagement is, of course, important. But it takes significant agency time and

resources—especially without a clear description in the Final Rule for how exactly to complete stakeholder engagement.

14. To comply with the Final Rule's state-plan timeline, ODEQ will have to begin working—i.e., expending resources—immediately.

15. It is difficult to project the number of hours and additional employees (or the diversion of existing employees) that will be required to implement the requirements of the Final Rule and to promulgate corresponding state rules and develop State Implementation Plan (SIP) updates to address the requirements of the Emission Guidelines (EG) in Subpart UUUUb. Considering the breadth of this rule, it would be prudent to expect an increased demand for staff support that could require adding to ODEQ's permitting,, compliance and enforcement, rules & planning, and emissions inventory staff. Additional administrative and management personnel would be needed in proportion to those staff increases.

16. Based on CO_2 emissions data from the subject units in 2023 and an estimation of generally recognized costs of CCS per ton, mandating the use of CCS technology in the Oklahoma facilities containing units subject to the Final Rule could cost more than a billion dollars per year. The up-front capital costs would exceed even that. Because of the Final Rule's aggressive timeline, utility owners and operators will have to incur costs immediately to comply with the Final Rule.

17. Storing CO_2 in geological reservoirs requires federal Class VI injection wells, for which EPA currently has primacy in Oklahoma. This is a time-consuming and onerous process. Further, the CCS requirements in the Final Rule could require Oklahoma to incorporate some type of CO_2 injection regulations into its state plan. Oklahoma is seeking Class VI delegation but has no reason to believe EPA will move quickly to either grant it primacy or to permit the wells itself.

18. ODEQ submitted comments on the Proposal during the comment period, including the following critiques, which remain accurate after the publication of the Final Rule.

a. The Proposal contains requirements that are excessively costly, overly complex, and unreasonably risky, and that offer too little benefit as compared to a no-action baseline. These requirements are likely to negatively affect reliability across the power sector in Oklahoma.

b. The U.S. Congress never provided EPA the essential tools or specific authority to regulate GHG emissions from the power sector in a meaningful or practical way. In offering the Proposal, EPA attempted to avoid the limitations on its attempts to creatively expand its authority under the Clean Air Act – limitations that were articulated in the U.S. Supreme Court's ruling in *West Virginia v. EPA*. In particular, EPA noted in the preamble that they focused on "measures that improve the pollution performance of individual sources." However, EPA's efforts in the Proposal fail to avoid the limitations on generation shifting imposed by the major questions doctrine and *West Virginia*.

c. The Proposal relies on CCS for BSER, which has not yet been demonstrated at scale. Ideally, emission limits should be technology neutral. Further, because utilities may need to choose a compliance pathway in advance – especially when considering the extensive infrastructure build-out and additional costs – there is a significant risk that utilities may expend large sums, in advance, on technologies which fail to mature leading to cost overruns and expenses that are often passed on to utility customers. It is also problematic that the technologies proposed as BSER for existing units had never been selected as Reasonable Available Control Technology (RACT) or Best Available Control Technology (BACT) under any major New Source Review permit identified in EPA's RACT/BACT/LAER Clearinghouse at the time of the Proposal. Additionally, one very real public health and safety concern that is expected in Oklahoma is the possibility of additional earthquakes should CCS be used in any appreciable volume.

d. In the Proposal, EPA describes meaningful engagement as a nebulous process that will be judged by the regional EPA office months, if not years, after submittal of the state plan. It also fails to properly understand or take account of remaining useful life and other factors.

19. The Federal Power Act and the Federal Energy Policy Act of 2005 govern the generation, transmission, and reliability of electric power. Those statutes reserve specific authority to the States instead of the federal government. In Oklahoma, the Oklahoma Corporation Commission is the state agency responsible for ensuring that consumers have reliable, low-cost electricity.

20. In addition to the increased costs that will be incurred to retrofit and operate CCS systems on existing coal and natural gas-fired boilers, the Final Rule's requirements for new units will add costs and will reduce the ability of utilities to construct a nimble and robust fleet of new simple cycle and combined cycle natural gas turbines that would have been expected, in the absence of the Final Rule, to facilitate the continued construction of renewable energy sources in Oklahoma. It is ironic that a rule intended to aid in the transition to renewable energy generation may have the effect of reducing the incentives that have aided Oklahoma utilities in the successful transition from almost complete reliance on fossil-fueled units to a flexible "all of the above" energy sector which, in 2023, relied on natural gas for 49.8%, wind for 42.0%, coal for 5.8%, and hydroelectric for 2.1% of Oklahoma's

electric generation. The fact that Oklahoma relied on coal for 62.2% of Oklahoma's electrical generation in 2001 shows just how far and how quickly Oklahoma has come in the absence of any EPA electric sector GHG reduction mandates.

21. In conclusion, it is my opinion that implementing the Final Rule will require ODEQ and other state agencies to immediately invest a great amount of time, effort, and resources to develop a state plan and will require Oklahoma to change the way it regulates emissions and the generation of electricity. These are unrecoverable costs.

22. The mandates in the Final Rule therefore frustrate the authority of ODEQ and constrain its ability to serve the citizens of Oklahoma, which is ODEQ's duty as required by Oklahoma law. Unless a stay is immediately granted, the Final Rule will impose significant and irreparable harm on the State of Oklahoma and its citizens through direct and immediate financial means.

<u>Lack of Harms by Entry of Stay</u>

23. Issuing a stay will cause no real harms—it would merely maintain the status quo. Further, the status quo has already represented a steady increase in renewable energy sources in Oklahoma, principally wind but with utility solar installations starting to ramp up generation as well. Natural gas, a lower-polluting source, has increased its share of Oklahoma's generation, but as wind generation has increased, natural gas use has fluctuated due to its combined role as a source of

inexpensive electricity and a backup for wind. Solar generation has increased from a negligible baseline in 2013 to 239 thousand Megawatt-hours in 2023. While the 2023 number is still low compared to natural gas and wind, the rate of growth of solar is substantial, increasing by 30% between 2021 and 2022 and 43% between 2022 and 2023. All of these changes have been happening in the absence of the kind of mandates embodied in the Final Rule.

24. The minimal purported benefits of the Final Rule and the time frame required to realize those benefits further support the reasonableness of a stay. EPA's own modeling ("Integrated Proposal Modeling and Updated Baseline Analysis," Docket ID No. EPA-HQOAR-2023-0072, July 7, 2023) released just prior to the close of the comment period on the Proposed Rule claimed that full implementation of the Proposed Rule would yield a 7.3% reduction in GHG emissions from the electricity sector per year by 2040. That 7.3% reduction is compared to a no-action baseline. It is notable that EPA's own estimated reductions in GHG emissions from the then-proposed Clean Power Plan (CPP) were exceeded even in the absence of that rule and those objectives were achieved ten years earlier than would have been required by the CPP. In short, EPA has underestimated the benefits of market forces while overclaiming the need for their interventions in that market. Further, EPA severed the requirements for reductions from existing natural gas-fired turbines in

the Final Rule. With that change in place, EPA's estimated GHG emissions reductions would have been even smaller than the 7.3% estimated.

25. I declare under penalty of perjury under the laws of the United States of America that the foregoing is true and correct.

Kendal Stegmann
Director, Air Quality Division
Oklahoma Department of
Environmental Quality

Date: May 10, 2024

EXHIBIT 23

UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

NATIONAL RURAL ELECTRIC COOPERATIVE ASSOCIATION, *Petitioner,* v. UNITED STATES ENVIRONMENTAL PROTECTION AGENCY, *et al.*, *Respondents*.	Case No. 24-1122

DECLARATION OF ROBERT C. HOCHSTETLER

I, Robert C. Hochstetler, declare as follows:

1. My name is Robert C. Hochstetler. I am the President and Chief Executive Officer of Central Electric Power Cooperative, Inc. ("Central Electric"), and have held that position since July 2014. I hold a Bachelor of Science degree in Electrical Engineering and four Master's degrees in Business Administration, Statistics, Strategic Management, and Public Administration. I have been employed in the electric utility industry since 1990, working for investor-owned utilities and electric cooperatives. Over the course of my career, I have managed various electric utility generating

assets, including coal and natural gas units as well as renewable generation. I am over the age of 18 years, and I am competent to testify concerning the matters in this declaration. I have personal knowledge of the facts set forth in this declaration, and if called and sworn as a witness, could and would competently testify to them.

2. Central Electric is a member of the National Rural Electric Cooperative Association ("NRECA"). This declaration is submitted in support of the legal challenges to the Environmental Protection Agency's final rule entitled *New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule*, 89 Fed. Reg. 39798 (May 9, 2024) (the "Final Rule" or "Rule"). I am familiar with Central Electric's operations, including power supply, transmission, compliance, workforce management, and electric markets in general. I also am familiar with how EPA's Final Rule will affect

Central Electric as well as its suppliers, members, members' consumers, and employees.

3. Central Electric is a not-for-profit generation and transmission cooperative owned by its members, the nineteen distribution cooperatives that operate in South Carolina. Central Electric provides wholesale electric service to its nineteen member cooperatives using more than 800 miles of transmission lines. Central Electric members provide service in all 46 of South Carolina's counties through 76,000 miles of distribution lines. Central Electric currently provides approximately 20,000,000 megawatt hours ("MWh") of energy to its members annually with a peak demand of approximately 4,600 megawatts ("MW").

OVERVIEW OF THE FINAL RULE

4. The Final Rule sets CO_2 emissions limits that States must apply to existing coal-fired steam units, under Section 111(d). 89 Fed. Reg. at 39840. The Rule also sets CO_2 emissions limits for new gas-fired combustion-turbine units, under Section 111(b). *Id.* at 39902. Both existing and new units must meet emissions limits roughly equal to what EPA says 90% carbon-

capture-and-sequestration can achieve. Existing units that cannot achieve this must shut down. New units that cannot achieve this must drastically reduce their output of electricity.

5. *Existing coal-fired units.* The Rule divides existing coal-fired steam units into three non-overlapping subsets: two are "subcategories" and one is an "applicability exemption." *Id.* at 39841. These subsets are defined by whether a unit has committed to permanently retire, and by the retirement date that a unit has committed to. *See id.* To be effective, these commitments must be included in State plans, which are due to EPA in 24 months. *Id.* at 39874. If a unit does not commit to retire, it is placed into the first subcategory by default. *See id.* at 39841.

6. The first subcategory is for "long-term" units, which EPA defines as units that plan to operate on or after January 1, 2039. *Id.* at 39801. EPA says that the best system for these units is CCS that captures 90% of the CO_2 from a unit. *Id.* at 39845. The first part of this "system" is the design and installation of CCS technology. *Id.* at 39846. After that, the captured CO_2 must be transported (usually via pipeline) to a sequestration site that can

permanently store it (usually underground). *See id.* EPA "assumes" that "work" toward "each component of CCS" will begin in June 2024, *id.* at 39874, and the Rule requires that work to be completed before January 1, 2032, *id.* at 39801.

7. The second subcategory is for "medium term" units: those that make a federally enforceable commitment to "permanently cease operation before January 1, 2039." *Id.* EPA's best system for this subcategory is "co-firing with natural gas[] at a level of 40 percent"—*i.e.*, transforming a coal unit into one that combusts both coal and natural gas. *Id.* EPA assumes that medium-term units will begin compliance work in June 2024, and the Rule requires those units to reach full compliance by January 1, 2030. *Id.* at 39893.

8. Third, units that make a federally enforceable commitment to permanently cease operating before January 1, 2032, have an "applicability exemption" and are not subject to the Rule. *Id.* at 39801. But "[i]f a source continues to operate past this date, it is no longer exempt," and is thus in violation of the state plan and the Clean Air Act. *Id.* at 39843; *see id.* at 39991.