ORAL ARGUMENT NOT YET SCHEDULED

No. 15-1381 (and consolidated cases)

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

STATE OF NORTH DAKOTA, *et al.*,

Petitioners,

v.

U.S. ENVIRONMENTAL PROTECTION AGENCY, *et al.*,

Respondents.

On Petition for Review of Final Agency Action
of the U.S. Environmental Protection Agency
80 Fed. Reg. 64,510 (Oct. 23, 2015)

STATE OF NORTH DAKOTA'S OPENING BRIEF

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DATED: October 13, 2016

CERTIFICATE AS TO PARTIES, RULINGS, AND RELATED CASES

Pursuant to Circuit Rule 28(a)(1), the State of North Dakota states as follows:

A. Parties, Intervenors, and Amici Curiae

These cases involve the following parties:

Petitioners:

No. 15-1381: State of North Dakota.

No. 15-1396: Murray Energy Corporation.

No. 15-1397: Energy & Environment Legal Institute.

No. 15-1399: State of West Virginia; State of Alabama; State of Arizona Corporation Commission; State of Arkansas; State of Florida; State of Georgia; State of Indiana; State of Kansas; Commonwealth of Kentucky; State of Louisiana; State of Louisiana Department of Environmental Quality; Attorney General Bill Schuette, People of Michigan; State of Missouri; State of Montana; State of Nebraska; The North Carolina Department of Environmental Quality; State of Ohio; State of Oklahoma; State of South Carolina; State of South Dakota; State of Texas; State of Utah; State of Wisconsin; and State of Wyoming.

No. 15-1434: International Brotherhood of Boilermakers, Iron Ship Builders, Blacksmiths, Forgers & Helpers, AFL-CIO.

No. 15-1438: Peabody Energy Corporation.

No. 15-1448: Utility Air Regulatory Group and American Public Power Association.

No. 15-1456: National Mining Association.

No. 15-1458: Indiana Utility Group.

No. 15-1463: United Mine Workers of America, AFL-CIO.

No. 15-1468: Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; and Southern Power Company.

No. 15-1469: Chamber of Commerce of the United States of America; National Association of Manufacturers; American Fuel & Petrochemical Manufacturers; National Federation of Independent Business; American Chemistry Council; American Coke and Coal Chemicals Institute; American Foundry Society; American Forest & Paper Association; American Iron and Steel Institute; American Wood Council; Brick Industry Association; Electricity Consumers Resource Council; Lignite Energy Council; National Lime Association; National Oilseed Processors Association; and Portland Cement Association.

No. 15-1481: American Coalition for Clean Coal Electricity.

No. 15-1482: Luminant Generation Company LLC; Oak Grove Management Company LLC; Big Brown Power Company LLC; Sandow Power Company LLC; Big Brown Lignite Company LLC; Luminant Mining Company LLC; and Luminant Big Brown Mining Company LLC.

No. 15-1484: National Rural Electric Cooperative Association; Basin Electric Power Cooperative; East Kentucky Power Cooperative, Inc.; Hoosier Energy Rural Electric Cooperative, Inc.; Minnkota Power Cooperative, Inc.; Sunflower

Electric Power Corporation; and Tri-State Generation and Transmission Association, Inc.

No. 16-1218: Murray Energy Corporation.

No. 16-1220: State of West Virginia; State of Alabama; State of Arizona Corporation Commission; State of Arkansas; State of Florida; State of Georgia; State of Indiana; State of Kansas; Commonwealth of Kentucky; State of Louisiana; State of Louisiana Department of Environmental Quality; Attorney General Bill Schuette, People of Michigan; State of Missouri; State of Montana; State of Nebraska; The North Carolina Department of Environmental Quality; State of Ohio; State of Oklahoma; State of South Carolina; State of South Dakota; State of Texas; State of Utah; State of Wisconsin; and State of Wyoming.

No. 16-1221: Utility Air Regulatory Group and American Public Power Association.

No. 16-1227: Energy & Environment Legal Institute.

Respondents:

Respondents are the United States Environmental Protection Agency (in Nos. 15-1381, 15-1397, 15-1434, 15-1448, 15-1456, 15-1463, 15-1481, 15-1484, 16-1221, 16-1227) and the United States Environmental Protection Agency and Gina McCarthy, Administrator (in Nos. 15-1396, 15-1399, 15-1438, 15-1458, 15-1468, 15-1469, 15-1480, 15-1482, 16-1218, 16-1220).

<u>Intervenors and *Amici Curiae*</u>:

Lignite Energy Council and Gulf Coast Lignite Coalition are Petitioner-Intervenors.

American Lung Association; Center for Biological Diversity; Clean Air Council; Clean Wisconsin; Conservation Law Foundation; Environmental Defense Fund; Natural Resources Defense Council; Ohio Environmental Council; Sierra Club; State of California by and through Governor Edmund G. Brown, Jr., and the California Air Resources Board, and Attorney General Kamala D. Harris; State of Connecticut; State of Delaware; State of Hawaii; State of Illinois; State of Iowa; State of Maine; State of Maryland; State of Minnesota by and through the Minnesota Pollution Control Agency; State of New Hampshire; State of New Mexico; State of New York; State of Oregon; State of Rhode Island; State of Vermont; State of Washington; Commonwealth of Massachusetts; Commonwealth of Virginia; District of Columbia; City of New York; Golden Spread Electric Cooperative, Inc.; NextEra Energy, Inc.; Calpine Corporation; The City of Austin d/b/a Austin Energy; The City of Los Angeles, by and through its Department of Water and Power; The City of Seattle, by and through its City Light Department; National Grid Generation, LLC; New York Power Authority; Pacific Gas and Electric Company; Sacramento Municipal Utility District; Tri-State Generation and Transmission Association, Inc. are Respondent-Intervenors.

B. <u>Rulings Under Review</u>

These consolidated cases involve final agency action of the United States Environmental Protection Agency entitled, "Standards of Performance for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units," published on October 23, 2015, at 80 Fed. Reg. 64,510.

C. <u>Related Cases</u>

These consolidated cases have not previously been before this Court or any other court.

Per the Court's order of March 24, 2016, the following case was severed and is being held in abeyance pending potential administrative resolution of biogenic carbon dioxide emissions issues in the Final Rule: *Biogenic CO2 Coalition v. EPA*, No. 15-1480.

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[1] Authorities upon which we chiefly rely are marked with asterisks.

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GLOSSARY

BSER	Best System of Emission Reduction
BTU	British Thermal Unit
CAA	Clean Air Act
CCS	Carbon Capture and Sequestration
CO_2	Carbon Dioxide
CO_2/MWh	Carbon Dioxide per Megawatt hour
EGU	Electric Generating Unit
EPA	United States Environmental Protection Agency
EPAct	Energy Policy Act of 2005
JA	Joint Appendix
lb/MMBtu	Pound per million BTUs
MATS Rule	National Emission Standards for Hazardous Air Pollutants From Coal and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units, 77 Fed. Reg. 9304, 9379 (Feb. 16, 2012)
NDDH	North Dakota Department of Health
NOx	Nitrogen Oxide

JURISDICTIONAL STATEMENT

Petitioner State of North Dakota ("North Dakota") seeks review of the final rule promulgated by the U.S. Environmental Protection Agency ("EPA") entitled "Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units; Final Rule," 80 Fed. Reg. 64,510 (Oct. 23, 2015) ("Rule"), Joint Appendix ("JA"), ___–___. North Dakota's petition for review was timely filed in this Court under § 307(b)(1) of the Clean Air Act ("CAA").[2]

STATEMENT OF ISSUES

1. Whether the Rule violates CAA § 111(b) by establishing a standard for coal-fueled EGUs based on a technology that is not adequately demonstrated for units fueled with "lignite" coal, which differs significantly from other coal forms;

2. Whether the Rule violates CAA § 111(b) by mandating a performance standard that is not achievable for lignite-fueled EGUs; and

3. Whether the Rule violates CAA § 307(d)(9) because it fails to subcategorize for lignite coal, despite EPA's past practice of subcategorizing for lignite and its acknowledgment in the record that lignite has distinct characteristics, making the Rule arbitrary, capricious, an abuse of discretion, or otherwise unlawful.

[2] The Table of Authorities provides parallel citations to the U.S. Code.

STATUTES AND REGULATIONS

This case involves regulations promulgated by EPA pursuant to a claim of authority under CAA § 111(b). The Rule is codified in 40 C.F.R. Part 60, Subpart TTTT. The addendum reproduces the pertinent regulations and statutory provisions.

INTRODUCTION

This case involves consolidated petitions for review of the Rule. By Order dated March 24, 2016, the Court allowed North Dakota to file its own briefs, separate from the other States. North Dakota focuses its brief on the Rule's application to electric generating units ("EGUs") that are fueled with lignite coal. As explained below, the Rule's application to lignite-fueled EGUs underscores the Rule's invalidity by showing clearly that the Rule violates the specific requirements of CAA § 111(b) and general requirements of CAA § 307(d)(9).

STATEMENT OF THE CASE

EPA issued the Rule as a component of the Executive Branch's program to address carbon dioxide ("CO_2") emissions from fossil fuel-fired EGUs. *See* Presidential Memorandum on Power Sector Carbon Pollution Standards, 1 Pub. Papers 457 (June 25, 2013). The Rule establishes "standards of performance" for new, modified, and reconstructed EGUs under CAA § 111(b).

In the Rule, EPA determined that the best system of emission reduction ("BSER") for new coal-fueled EGUs is "a highly efficient supercritical pulverized coal-fired boiler using post-combustion" carbon capture and storage ("CCS"). This

BSER involves new coal-fueled EGUs capturing a significant portion of their CO_2 emissions post-combustion and arranging to have those emissions permanently stored in "deep saline formations." The Rule establishes a performance standard for new coal-fueled EGUs of 1400 lbs CO_2/MWh, which EPA contends can be met through application of the BSER.[3]

In reality, the Rule is a *de facto* ban on new coal-fired EGUs—particularly those EGUs fueled with lignite, a distinctive form of coal—because the BSER is not adequately demonstrated for lignite-fueled EGUs, and the standard of performance is not achievable for lignite-fueled EGUs. This is significant to North Dakota, where in 2013, coal accounted for 99.4 percent of the State's fossil-fuel-powered electricity generation, nearly all of it from lignite coal. *See* U.S. Energy Information Administration, North Dakota Electricity Profile (2013), *http://www.eia.gov/electricity/state/NorthDakota*. North Dakota has an active and robust lignite coal and lignite-fueled energy producing industry, which the State has long promoted through a statutory state-industry partnership aimed at protecting and enhancing future use of North Dakota's abundant lignite resources. *See* N.D. Cent. Code § 54-17.5-01. The North Dakota lignite industry supports more than 28,000 jobs and produces about 30 million tons of lignite coal annually. *Id.* Lignite's

[3] North Dakota focuses its brief on newly constructed EGUs, although it has similar concerns with the BSER established for reconstructed and modified units, *see* 80 Fed. Reg. 64,512, JA___.

reliability and efficacy allows North Dakota to keep its retail price of electricity low, which is important given the significant increase in demand for electricity projected over the next 20 years due to the Bakken Formation oil reserves in the Williston Basin area, which spans North Dakota, South Dakota, and Montana. NDDH Comments at 8, EPA-HQ-OAR-2013-0495-10870, JA___.

Lignite coal has characteristics that make it very different from other coals. First, the physical and chemical composition of lignite, including higher CO_2 emissions, typically requires larger, more energy-intensive emission-control technologies than other coal-fired units. LEC Comments at 2, JA___. Second, lignite's far lower BTU content by weight results in much higher transport costs, because compared to other coal units, substantially greater amounts of lignite must be transported to supply lignite-fueled EGUs. This limits where new lignite-fueled EGUs can be sited, as they invariably must be co-located with the mines that supply their coal. *Id.*; *see also* GCLC Comments at 8, EPA-HQ-OAR-2013-0495-10556, JA___.

EPA regulations have historically recognized differences in types of coals used in power generation, and the agency acknowledges the distinctive qualities of lignite in the administrative record here. *See* EPA, Regulatory Impact Analysis for the Final Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units ("RIA"), at 2-26 (Aug. 2015, rev. Oct. 23, 2015), EPA-HQ-OAR-2013-0495-11877, JA___ (showing lignite has a higher CO_2 emission rate than subbituminous and bituminous coals). Moreover, courts have recognized the uniqueness of lignite in establishing technology-based standards. For example, in *United States v. Minnkota Power Coop., Inc.*, 831 F. Supp. 2d 1109, 1125 (D.N.D. 2011), which involved another CAA provision that similarly required appropriate control technology determinations for EGUs, North Dakota based its determination of "best available control technology" on the unique characteristics of lignite. Against a challenge by EPA, the district court upheld the State's technology determination, in part because it rested on "the differences between North Dakota lignite and other coals nationwide." *Id.*; *see also id.* at 1126 (noting research showing the "behavior of the lignites from North Dakota is the most complex and severe of any coals in the world") (internal quotations omitted). EPA declined to appeal.

In other recent rulemakings, EPA similarly recognized and accounted for the uniqueness of lignite in electric power generation. *See e.g.,* 77 Fed. Reg. 9304, 9379 (Feb. 16, 2012), JA___ ("MATS Rule") (subcategorizing coal types, including lignite, based on different heat generation and mercury-emission characteristics). Here, EPA departs from that established practice with the only offered explanation being "we have concluded that these standards are achievable by all the primary coal types." 80 Fed. Reg. at 64,600, JA___.

SUMMARY OF ARGUMENT

EPA knows from experience, and indeed recognized here, lignite's distinctive emissions characteristics. Moreover, the administrative record reflects that lignite's unique characteristics present distinctive technological challenges, including with respect to emission-control technologies. EPA nevertheless failed to establish that the Rule's BSER is "adequately demonstrated" or that the performance standard is "achievable," as CAA § 111(b) explicitly requires, for new lignite-fueled EGUs. That makes the Rule invalid, because this Court has held that performance standards must meet those requirements as applied to the entire source category—here, coal-fueled EGUs, including lignite-fueled units.

Despite commenters' requests to treat lignite-fueled EGUs separately as EPA has done in prior similar rulemakings, here EPA refused to create a subcategory for lignite-fueled EGUs. That decision was arbitrary and capricious.

The Rule is unlawful and must be vacated.[4]

STANDING

North Dakota has standing, first, because the Rule imposes a CO_2 performance standard that is unachievable for lignite-fueled EGUs and, as a result, is a *de facto* ban on use of North Dakota's abundant lignite resources in new EGUs. Glatt Decl. ¶¶ 7, 9.

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[4] North Dakota fully supports—and incorporates by reference—the additional arguments made in the other State Petitioners' brief, and in the Non-State Petitioners' brief, explaining why the Rule is invalid.

Second, the Rule significantly impairs North Dakota's sovereign authority under both state law and the CAA. North Dakota has a statutory obligation to protect, preserve, and enhance development of the State's lignite resources for the benefit of its citizens. N.D. Cent. Code § 54-17.5-01; *see also* Fine Decl. ¶¶ 4, 8. By effectively banning new lignite-fueled facilities, the Rule fundamentally preempts North Dakota law, and installs EPA as dictator of energy policy—displacing the traditional and statutory role held by State agencies. Christmann Decl. ¶¶ 9–12; Fine Decl. ¶ 11; Glatt Decl. ¶¶ 8–9. North Dakota's Public Service Commission is vested with regulatory authority over new EGU additions. Christmann Decl. ¶¶ 3–4. The North Dakota Department of Health administers federal and state laws governing air quality, which includes permitting new EGUs. Glatt Decl. ¶¶ 3–4. The North Dakota Industrial Commission implements special programs to foster the State's development of new lignite resources. Fine Decl. ¶¶ 3–4, 6–10. By effectively banning new lignite-fueled EGUs, the Rule divests these State agencies of their respective statutory roles and authorities.

Third, North Dakota has standing because the Rule for new EGUs is a legal prerequisite for EPA's separate rule under CAA § 111(d) for existing EGUs, which injures North Dakota because it forces the State to either formulate a state plan or accept a federal plan, and it forces the shutdown or curtailment of lignite-fueled EGUs in the state. EPA admits the 111(d) rule could not legally exist without the Rule. 80 Fed. Reg. 64,662, 64,702 (Oct. 23, 2015), JA___.

These factors are more than sufficient to meet the causation, traceability, and redressability required for standing, especially in light of the "special solicitude" North Dakota must be afforded in this case. *Massachusetts v. EPA*, 549 U.S. 497, 520 (2007).

STANDARD OF REVIEW

Pursuant to CAA § 307(d)(9), the Court must set aside a final agency action that is "arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with law; contrary to constitutional right, power, privilege, or immunity; or in excess of statutory jurisdiction, authority, or limitations or short of statutory right."

ARGUMENT

I. The Rule Violates the Clean Air Act.

EPA's authority under CAA § 111(b) to set "standards of performance for new sources" is subject to important limitations: EPA must define the standards to "reflect[ ] the degree of emission limitation *achievable* through the [BSER] which . . . the Administrator determines has been *adequately demonstrated*." CAA § 111(a)(1) (emphasis added). Critically, "achievability" and "adequately demonstrated" are *separate* requirements, and both must be independently proven by EPA for the entire source category.

Because EPA explicitly seeks to regulate lignite-fueled EGUs under the Rule, 40 C.F.R. § 60.5580 ("[c]oal means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite . . . "), the agency must show that the BSER is "adequately demonstrated" for lignite-fueled EGUs and that the standard of performance is "achievable" for lignite-fueled EGUs. EPA fails on both accounts.

A. The BSER in the Rule is Not "Adequately Demonstrated" for Lignite-Fueled EGUs.

1. No Lignite-Fueled EGU Employs the BSER.

EPA fails to cite any real-world, commercial-scale usage of the entire BSER. *See* EPA, TSD, Literature Survey of Carbon Capture Technology at 10, 40, 43–44 (July 10, 2015), EPA-HQ-OAR-2013-0495-11773, JA___, ___, ___–___. This undermines the Rule as applied to *any* coal-fired EGU, but it is especially fatal for lignite-fired EGUs, which, as EPA acknowledges, are technologically and operationally distinct from traditional coal-fired EGUs due to lignite's lower BTU content, higher CO_2 emissions and different chemical composition, *see e.g.*, RIA at 2-26, JA___. These differences pose unresolved technical challenges for the deployment of CCS at lignite-fueled EGUs. *See Minnkota*, 831 F.Supp. 2d at 1126 (recognizing the "unique characteristics" of lignite "present significant challenges to successful application of" control technologies).

EPA's failure to present real-world, commercial-scale usage of the BSER is fatal, because to be "adequately demonstrated," a "system" must be in commercial use or capable of commercial deployment. *Sierra Club v. Costle*, 657 F.2d 298, 341, n.157 (D.C. Cir. 1981). It must be more than just "technically feasible," 80 Fed. Reg. 64,513; rather, EPA must show that a BSER is commercially available, *Costle,* 657 F.2d at 364; *Portland Cement Ass'n*, *v. Ruckelshaus,* 486 F.2d 375, 391 (D.C.Cir. 1973), "reasonably efficient," *Essex Chem. Corp. v. Ruckelshaus*, 486 F.2d 427, 433 (D.C. Cir. 1973), and not "unreasonably costly," *Costle*, 657 F.2d at 343.

The record does not establish that the Rule's BSER meets these requirements as applied to lignite-fueled EGUs, or any EGUs. EPA describes multiple facilities—some of which are fueled by lignite—that employ individual components of the BSER. However, EPA does not cite a single EGU in the entire world that employs (or can employ) *all* the components of its BSER. Moreover, the Rule's performance standard is not "achievable" through the BSER, *see* discussion *infra* Part I.B, and thus is a *de facto* ban on lignite-fueled EGUs. As a result, the BSER is not only "unreasonably costly" for lignite-fueled EGUs, *Costle*, 657 F.2d at 343, it effectively nullifies EPA's statutory obligation to "take into account the costs of achieving the emission reductions" prescribed for lignite-fueled EGUs. *Portland Cement*, 486 F.2d at 387.

The Rule acknowledges the "system" it requires is not in use anywhere and takes the position that EPA can find a system is "demonstrated" if the system's *components* are "technically feasible," 80 Fed. Reg. at 64,556, JA___. That is contrary to this Court's instruction in the decisions cited above that "adequately demonstrated" means a BSER is commercially "available" to be "install[ed] in new plants," "reasonably efficient" and not "unreasonably costly."

2. EPA Improperly Relied on Government-Subsidized EGUs.

The Energy Policy Act of 2005 ("EPAct") prohibits EPA from considering projects subsidized by the U.S. Department of Energy's Clean Coal Power Initiative ("CCPI") to support a finding that a BSER is "adequately demonstrated." *See* 42 U.S.C. § 15962(i)).

As EPA confesses, 80 Fed. Reg. at 64,526 n.74, JA___, it did just that. *All but one* of the EGUs used to support its finding that the BSER is "adequately demonstrated" received CCPI funding. While reliance on these facilities is problematic for myriad other reasons, it is plainly prohibited by EPAct.

3. EPA's Reliance on Boundary Dam Does Not Provide a Rational Basis for Concluding that the BSER is "Adequately Demonstrated."

Ironically, the lone EGU on which EPA relied that was *not* subsidized by the U.S. government, SaskPower's Boundary Dam, was heavily subsidized by the Canadian government. Budget Implementation Act 2008, S.C. 2008, c. 28, s. 138 (Can.), JA___. This undeniably violates the logic behind EPAct—that projects are subsidized because they are otherwise nonviable—and SaskPower even admitted that "[f]ederal funding was the catalyst for the project." IEAGHG, "Integrated Carbon Capture and Storage Project at SaskPower's Boundary Dam Power Station," at 24 (Aug. 2015), JA___.

EPA's reliance on Boundary Dam is improper for other reasons. The project had numerous financial and operational failings, *see e.g.*, UARG Reconsideration

Petition at 3–8, EPA-HQ-OAR-2013-0495-11894, JA___, and its capital costs are exorbitant—at proposal, it was expected to cost $1.355 billion and is already $115 million over budget. NDDH Comments at 6, JA___. Power production, by comparison, is miniscule, with the unit only producing 160 MW gross and 110 MW net due to a 31 percent parasitic load—most of it consumed by CCS—which is well above the normal 7–12 percent. *Id.* at 7, JA___.

Beyond these flaws, Boundary Dam cannot properly be relied upon as an "adequate demonstration" because it commenced operation only ten months prior to the Rule being signed. 80 Fed. Reg. at 64,549, JA___. Because compliance with the Rule's performance standard is measured over an EGU's 12-month operating period, *see* 40 C.F.R. § 60.5540(a), EPA's determination is deficient and exactly the sort of "crystal ball inquiry" it is prohibited from making. *Portland Cement,* 486 F.2d at 391.

4. Sequestration in Deep Saline Formations Has Not Been "Adequately Demonstrated" for *Any* EGU in North America.

Because the Rule's performance standard is nationally applicable, *see* CAA § 111(f)(2)(c), it must be based on a BSER that has been "adequately demonstrated" for use anywhere in the country. In *Costle,* for example, this Court found that a water-dependent control technology cannot be a *nationwide* "best system" because it would have "disastrous" effects on the water supply in arid western states. *See* 657 F.2d at 330; *see also Nat'l Lime Ass'n v. EPA*, 627 F.2d 416, 441–43 (D.C. Cir. 1980) (rejecting standard that did not account for "regional variations"). Here, the Rule's "system" will have disastrous effects on North Dakota because it effectively bans new lignite-fueled EGUs.

Even assuming that EPA need only prove "components" of the BSER are adequately demonstrated, the Rule fails because individual components are not "adequately demonstrated" for use in North Dakota. As the Rule recognizes, "whether all new steam-generating sources can implement" the BSER is "dependent on the geographic scope." 80 Fed. Reg. at 64,541, JA___. EPA admits that large areas of the U.S.—including significant portions of North Dakota—do not have *any* identified deep saline formations, *id.* at 64,576-77, JA___, and even in areas that supposedly do, EPA acknowledges that not all such formations are suitable for sequestration. *Id.* at 64,573, JA___.

B. The Standard in the Final Rule is Not "Achievable" for Lignite-Fueled EGUs, and EPA Failed to Even Consider Virgin Lignite in Setting the Standard.

EPA must establish that the standards derived from the BSER are "achievable" by sources in "the industry as a whole," *Nat'l Lime*, 627 F.2d at 429, 431 & n.46, 433, and EPA must account for "regional variations" in setting the standards. *Id.* at 442. Here, EPA failed to show that its standard is achievable for new lignite-fueled units (it is not), and EPA failed to even consider the virgin lignite that prevails in North Dakota, which EPA conceded has different CO_2 emission characteristics. *See supra* pp. 4, 9.

EPA's "one size fits all coal-fueled EGUs" performance standard is based, not on any real-world evidence, but instead on a National Energy Technology Laboratory report that analyzes only one type of coal, Illinois No. 6 Coal, which is a medium-BTU, bituminous coal that burns more efficiently than low-BTU virgin lignite coal, the predominant coal in North Dakota. DOE, National Energy Technology Laboratory, "Cost and Performance Baseline for Fossil Energy Plants, Vol. 1a: Bituminous Coal (PC) and Natural Gas to Electricity, Rev. 3" at 26 (July 6, 2015), DOE/NETL-2015/1723, EPA-HQ-OAR-2013-0495-11341 ("NETL July 2015 Report"), JA___. The report's analysis is thus not "representative of potential industry-wide performance, given the range of variables that affect the achievability of the standard," *Costle*, 657 F.2d at 377, or of the "regional variations" of coal types. *Nat'l Lime*, 627 F.2d at 441–43. Therefore, EPA's claim that the standard for new coal-fueled units is achievable "for all fuel types, under a wide range of conditions, throughout the United States," 80 Fed. Reg. at 64,513, JA___, lacks record support particularly for lignite-fueled EGUs. EPA's claim is wrong as applied to lignite, because lignite's "unique characteristics" "present significant challenges to successful application of control technologies. *Minnkota*, 831 F. Supp. 2d at 1126.

In its "achievability" discussion, EPA discusses utilities "burning bituminous coal" as well as utilities "burning subbituminous coal or 'dried lignite,'" 80 Fed. Reg. at 64,513, JA___, but nowhere does EPA address achievability for a unit burning virgin, *non-dried*, lignite—which differs significantly from dried lignite and is what most lignite-fueled EGUs in North Dakota use. Indeed, EPA's many references to "dried lignite" in the Rule's preamble highlight the lack of *any* discussion of virgin, non-dried lignite, which is lower in BTUs, higher in moisture content and produces more CO_2 emissions. *See* 80 Fed. Reg. 64,513, 64,548, 64,560, 64,562, 64,574, JA___, ___, ___, ___, ___. Moreover, as recognized in a study that EPA cites in a footnote, drying lignite requires another undemonstrated technology for which "cost and techno-economic information is limited" and "[t]he actual cost depends both on the properties of the lignite in question and the operational parameters." *See id.* at 64,513, n.7, JA___ (citation omitted).

EPA's failure to account for regional variations or consider virgin lignite in its achievability analysis, or consequently to show that the Rule's performance standard can be met by the "industry as a whole," makes the Rule invalid.

II. EPA's Failure to Subcategorize for Lignite Violates CAA § 307(d)(9) Because it is Arbitrary and Capricious.

Despite subcategorizing for lignite in other, similar rulemakings, *see e.g.,* MATS Rule at 9379, JA___, EPA refused to subcategorize in this Rule, even though the agency received comments "suggest[ing] that due to high moisture content and high relative CO_2 emissions of lignite, lignite-fired units should have its own [sic] subcategory." 80 Fed. Reg. at 64,600, JA___. EPA offers no explanation for its refusal to subcategorize, asserting only that it "concluded that these standards are achievable by all the primary coal types." *Id.* This conclusion is arbitrary and capricious.

In setting new source performance standards, CAA § 111(b)(2) provides that "[t]he [EPA] Administrator may distinguish among classes, types, and sizes within categories of new sources for the purpose of establishing such standards." EPA's implementing rules for existing sources go even further, stating that "the Administrator . . . *will* specify different emission guidelines or compliance times or both for different sizes, types, and classes of designated facilities when costs of control, physical limitations, geographical location, or similar factors make subcategorization appropriate." 40 C.F.R. § 60.22(b)(5) (emphasis added). Here, the physical and operational differences between EGUs that use lignite versus other coal types, along with its regional abundance in North Dakota, make subcategorization for lignite-fueled EGUs appropriate.

Long ago, EPA recognized it must establish subcategories to set emission guidelines based on "what is reasonably achievable *by particular classes* of existing sources." State Plans for the Control of Certain Pollutants from Existing Facilities, 40 Fed. Reg. 53,340, 53,343 (Nov. 17, 1975) (emphasis added). Hence, EPA anticipated that subcategorization would be appropriate "[i]n most if not all cases" with "substantial variation in the degree of control required for particular sources rather than identical standards for all sources." *Id.* Thus, EPA knows not only when to subcategorize, but how to do it. As shown in the MATS Rule, that same logic applies to new sources.

The MATS Rule established for both existing *and* new sources a subcategory for lignite under the larger coal category, based on lignite's distinctive composition and emission characteristics, and because lignite units are "universally constructed 'at or near' a mine containing" lignite. MATS Rule at 9379, JA___.[5] That limitation makes CCS particularly difficult to implement for lignite-fueled EGUs in North Dakota, significant portions of which, as EPA recognizes, have no deep saline formations. 80 Fed. Reg. at 64,576-77, JA___.

Subcategorization was not only appropriate here, it made practical sense. Commenters insisted on subcategorization because "[l]ignite-fired power plants are technologically and operationally distinct from traditional coal-fired power plants and include different design elements that warrant and require a separate subcategory." GCLC Comments at 8, JA___; *see also* NDDH Comments at 1, JA___ (referencing *Minnkota*, where North Dakota's control technology determination for lignite was upheld because of lignite's unique characteristics). In the MATS Rule, EPA found these same factors warranted subcategorization. Here, EPA's failure to adequately address these comments or explain why EPA reached the opposite conclusion is

[5] In recognizing North Dakota lignite's distinctive qualities in particular, the MATS Rule set a NOx emission limit of 0.8 lb/MMBtu for lignite mined in North Dakota, South Dakota, and Montana, versus a limit of 0.6 lb/MMBtu for other lignites. *See* 40 C.F.R. § 60.44Da(a)(1).

arbitrary and capricious. *See Motor Vehicle Mfrs. Ass'n v. State Farm Mut. Auto. Ins. Co.,* 463 U.S. 29, 43 (1983); *cf. Steger v. Def. Investigative Serv.*, 717 F.2d 1402, 1406 (D.C. Cir. 1983) (providing that an agency cannot "treat similar situations dissimilarly and, indeed, can be said to be at its most arbitrary when it does so.").

CONCLUSION

For the foregoing reasons, the State of North Dakota's petition should be granted, and the Rule should be vacated.

CERTIFICATE OF COMPLIANCE

Pursuant to Rule 32(a)(7)(C) of the Federal Rules of Appellate Procedure and Circuit Rules 32(a)(1) and 32(a)(2)(C), I hereby certify that the foregoing State of North Dakota's Opening Brief contains 3,970 words, as counted by a word processing system that includes headings, footnotes, quotations, and citations in the count, and therefore is within the word limit set by the Court.

Dated: October 13, 2016

/s/ Paul M. Seby

CERTIFICATE OF SERVICE

I hereby certify that on this 13th day of October 2016, a copy of the foregoing State of North Dakota's Opening Brief was served electronically through the Court's CM/ECF system on all ECF-registered counsel.

/s/ Paul M. Seby

ORAL ARGUMENT NOT YET SCHEDULED

No. 15-1381 (and consolidated cases)

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

STATE OF NORTH DAKOTA, *et al.*,

Petitioners,

v.

U.S. ENVIRONMENTAL PROTECTION AGENCY, *et al.*,

Respondents.

On Petition for Review of Final Agency Action
of the U.S. Environmental Protection Agency
80 Fed. Reg. 64,510 (Oct. 23, 2015)

STATE OF NORTH DAKOTA'S ADDENDUM PURSUANT TO CIRCUIT RULE 28(a)(5)

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DATED: October 13, 2016

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CERTIFICATE OF SERVICE

I hereby certify that, on this 13th day of October 2016, a copy of the State of North Dakota's Addendum Pursuant to Circuit Rule 28(a)(5) was served electronically through the Court's CM/ECF system on all ECF-registered counsel.

/s/ Paul M. Seby

STATUTES

United States Code Annotated
Title 42. The Public Health and Welfare
Chapter 85. Air Pollution Prevention and Control (Refs & Annos)
Subchapter I. Programs and Activities
Part A. Air Quality and Emissions Limitations (Refs & Annos)

42 U.S.C.A. § 7411

§ 7411. Standards of performance for new stationary sources

Currentness

(a) Definitions

For purposes of this section:

(1) The term “standard of performance” means a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.

(2) The term “new source” means any stationary source, the construction or modification of which is commenced after the publication of regulations (or, if earlier, proposed regulations) prescribing a standard of performance under this section which will be applicable to such source.

(3) The term “stationary source” means any building, structure, facility, or installation which emits or may emit any air pollutant. Nothing in subchapter II of this chapter relating to nonroad engines shall be construed to apply to stationary internal combustion engines.

(4) The term “modification” means any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted.

(5) The term “owner or operator” means any person who owns, leases, operates, controls, or supervises a stationary source.

(6) The term “existing source” means any stationary source other than a new source.

(7) The term “technological system of continuous emission reduction” means--

(A) a technological process for production or operation by any source which is inherently low-polluting or nonpolluting, or

(B) a technological system for continuous reduction of the pollution generated by a source before such pollution is emitted into the ambient air, including precombustion cleaning or treatment of fuels.

(8) A conversion to coal (A) by reason of an order under section 2(a) of the Energy Supply and Environmental Coordination Act of 1974 [15 U.S.C.A. § 792(a)] or any amendment thereto, or any subsequent enactment which supersedes such Act [15 U.S.C.A. § 791 et seq.], or (B) which qualifies under section 7413(d)(5)(A)(ii) of this title, shall not be deemed to be a modification for purposes of paragraphs (2) and (4) of this subsection.

(b) List of categories of stationary sources; standards of performance; information on pollution control techniques; sources owned or operated by United States; particular systems; revised standards

(1)(A) The Administrator shall, within 90 days after December 31, 1970, publish (and from time to time thereafter shall revise) a list of categories of stationary sources. He shall include a category of sources in such list if in his judgment it causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare.

(B) Within one year after the inclusion of a category of stationary sources in a list under subparagraph (A), the Administrator shall publish proposed regulations, establishing Federal standards of performance for new sources within such category. The Administrator shall afford interested persons an opportunity for written comment on such proposed regulations. After considering such comments, he shall promulgate, within one year after such publication, such standards with such modifications as he deems appropriate. The Administrator shall, at least every 8 years, review and, if appropriate, revise such standards following the procedure required by this subsection for promulgation of such standards. Notwithstanding the requirements of the previous sentence, the Administrator need not review any such standard if the Administrator determines that such review is not appropriate in light of readily available information on the efficacy of such standard. Standards of performance or revisions thereof shall become effective upon promulgation. When implementation and enforcement of any requirement of this chapter indicate that emission limitations and percent reductions beyond those required by the standards promulgated under this section are achieved in practice, the Administrator shall, when revising standards promulgated under this section, consider the emission limitations and percent reductions achieved in practice.

(2) The Administrator may distinguish among classes, types, and sizes within categories of new sources for the purpose of establishing such standards.

(3) The Administrator shall, from time to time, issue information on pollution control techniques for categories of new sources and air pollutants subject to the provisions of this section.

(4) The provisions of this section shall apply to any new source owned or operated by the United States.

(5) Except as otherwise authorized under subsection (h) of this section, nothing in this section shall be construed to require, or to authorize the Administrator to require, any new or modified source to install and operate any particular technological system of continuous emission reduction to comply with any new source standard of performance.

(6) The revised standards of performance required by enactment of subsection (a)(1)(A)(i) and (ii) of this section shall be promulgated not later than one year after August 7, 1977. Any new or modified fossil fuel fired stationary source which commences construction prior to the date of publication of the proposed revised standards shall not be required to comply with such revised standards.

(c) State implementation and enforcement of standards of performance

(1) Each State may develop and submit to the Administrator a procedure for implementing and enforcing standards of performance for new sources located in such State. If the Administrator finds the State procedure is adequate, he shall delegate to such State any authority he has under this chapter to implement and enforce such standards.

(2) Nothing in this subsection shall prohibit the Administrator from enforcing any applicable standard of performance under this section.

(d) Standards of performance for existing sources; remaining useful life of source

(1) The Administrator shall prescribe regulations which shall establish a procedure similar to that provided by section 7410 of this title under which each State shall submit to the Administrator a plan which (A) establishes standards of performance for any existing source for any air pollutant (i) for which air quality criteria have not been issued or which is not included on a list published under section 7408(a) of this title or emitted from a source category which is regulated under section 7412 of this title but (ii) to which a standard of performance under this section would apply if such existing source were a new source, and (B) provides for the implementation and enforcement of such standards of performance. Regulations of the Administrator under this paragraph shall permit the State in applying a standard of performance to any particular source under a plan submitted under this paragraph to take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies.

(2) The Administrator shall have the same authority--

(A) to prescribe a plan for a State in cases where the State fails to submit a satisfactory plan as he would have under section 7410(c) of this title in the case of failure to submit an implementation plan, and

(B) to enforce the provisions of such plan in cases where the State fails to enforce them as he would have under sections 7413 and 7414 of this title with respect to an implementation plan.

In promulgating a standard of performance under a plan prescribed under this paragraph, the Administrator shall take into consideration, among other factors, remaining useful lives of the sources in the category of sources to which such standard applies.

(e) Prohibited acts

After the effective date of standards of performance promulgated under this section, it shall be unlawful for any owner or operator of any new source to operate such source in violation of any standard of performance applicable to such source.

(f) New source standards of performance

(1) For those categories of major stationary sources that the Administrator listed under subsection (b)(1)(A) of this section before November 15, 1990, and for which regulations had not been proposed by the Administrator by November 15, 1990, the Administrator shall--

(A) propose regulations establishing standards of performance for at least 25 percent of such categories of sources within 2 years after November 15, 1990;

(B) propose regulations establishing standards of performance for at least 50 percent of such categories of sources within 4 years after November 15, 1990; and

(C) propose regulations for the remaining categories of sources within 6 years after November 15, 1990.

(2) In determining priorities for promulgating standards for categories of major stationary sources for the purpose of paragraph (1), the Administrator shall consider--

(A) the quantity of air pollutant emissions which each such category will emit, or will be designed to emit;

(B) the extent to which each such pollutant may reasonably be anticipated to endanger public health or welfare; and

(C) the mobility and competitive nature of each such category of sources and the consequent need for nationally applicable new source standards of performance.

(3) Before promulgating any regulations under this subsection or listing any category of major stationary sources as required under this subsection, the Administrator shall consult with appropriate representatives of the Governors and of State air pollution control agencies.

(g) Revision of regulations

(1) Upon application by the Governor of a State showing that the Administrator has failed to specify in regulations under subsection (f)(1) of this section any category of major stationary sources required to be specified under such regulations, the Administrator shall revise such regulations to specify any such category.

(2) Upon application of the Governor of a State, showing that any category of stationary sources which is not included in the list under subsection (b)(1)(A) of this section contributes significantly to air pollution which may reasonably be anticipated to endanger public health or welfare (notwithstanding that such category is not a category of major stationary sources), the Administrator shall revise such regulations to specify such category of stationary sources.

(3) Upon application of the Governor of a State showing that the Administrator has failed to apply properly the criteria required to be considered under subsection (f)(2) of this section, the Administrator shall revise the list under subsection (b)(1)(A) of this section to apply properly such criteria.

(4) Upon application of the Governor of a State showing that--

(A) a new, innovative, or improved technology or process which achieves greater continuous emission reduction has been adequately demonstrated for any category of stationary sources, and

(B) as a result of such technology or process, the new source standard of performance in effect under this section for such category no longer reflects the greatest degree of emission limitation achievable through application of the best technological system of continuous emission reduction which (taking into consideration the cost of achieving such emission reduction, and any non-air quality health and environmental impact and energy requirements) has been adequately demonstrated,

the Administrator shall revise such standard of performance for such category accordingly.

(5) Unless later deadlines for action of the Administrator are otherwise prescribed under this section, the Administrator shall, not later than three months following the date of receipt of any application by a Governor of a State, either--

(A) find that such application does not contain the requisite showing and deny such application, or

(B) grant such application and take the action required under this subsection.

(6) Before taking any action required by subsection (f) of this section or by this subsection, the Administrator shall provide notice and opportunity for public hearing.

(h) Design, equipment, work practice, or operational standard; alternative emission limitation

(1) For purposes of this section, if in the judgment of the Administrator, it is not feasible to prescribe or enforce a standard of performance, he may instead promulgate a design, equipment, work practice, or operational standard, or combination thereof, which reflects the best technological system of continuous emission reduction which (taking into consideration the cost of achieving such emission reduction, and any non-air quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated. In the event the Administrator promulgates a design or equipment standard under this subsection, he shall include as part of such standard such requirements as will assure the proper operation and maintenance of any such element of design or equipment.

(2) For the purpose of this subsection, the phrase "not feasible to prescribe or enforce a standard of performance" means any situation in which the Administrator determines that (A) a pollutant or pollutants cannot be emitted through a conveyance designed and constructed to emit or capture such pollutant, or that any requirement for, or use of, such a conveyance would be inconsistent with any Federal, State, or local law, or (B) the application of measurement methodology to a particular class of sources is not practicable due to technological or economic limitations.

(3) If after notice and opportunity for public hearing, any person establishes to the satisfaction of the Administrator that an alternative means of emission limitation will achieve a reduction in emissions of any air pollutant at least equivalent to the reduction in emissions of such air pollutant achieved under the requirements of paragraph (1), the Administrator shall permit the use of such alternative by the source for purposes of compliance with this section with respect to such pollutant.

(4) Any standard promulgated under paragraph (1) shall be promulgated in terms of standard of performance whenever it becomes feasible to promulgate and enforce such standard in such terms.

(5) Any design, equipment, work practice, or operational standard, or any combination thereof, described in this subsection shall be treated as a standard of performance for purposes of the provisions of this chapter (other than the provisions of subsection (a) of this section and this subsection).

(i) Country elevators

Any regulations promulgated by the Administrator under this section applicable to grain elevators shall not apply to country elevators (as defined by the Administrator) which have a storage capacity of less than two million five hundred thousand bushels.

(j) Innovative technological systems of continuous emission reduction

(1)(A) Any person proposing to own or operate a new source may request the Administrator for one or more waivers from the requirements of this section for such source or any portion thereof with respect to any air pollutant to encourage the use of an innovative technological system or systems of continuous emission reduction. The Administrator may, with the consent of the Governor of the State in which the source is to be located, grant a waiver under this paragraph, if the Administrator determines after notice and opportunity for public hearing, that--

(i) the proposed system or systems have not been adequately demonstrated,

(ii) the proposed system or systems will operate effectively and there is a substantial likelihood that such system or systems will achieve greater continuous emission reduction than that required to be achieved under the standards of performance which would otherwise apply, or achieve at least an equivalent reduction at lower cost in terms of energy, economic, or nonair quality environmental impact,

(iii) the owner or operator of the proposed source has demonstrated to the satisfaction of the Administrator that the proposed system will not cause or contribute to an unreasonable risk to public health, welfare, or safety in its operation, function, or malfunction, and

(iv) the granting of such waiver is consistent with the requirements of subparagraph (C).

In making any determination under clause (ii), the Administrator shall take into account any previous failure of such system or systems to operate effectively or to meet any requirement of the new source performance standards. In determining whether an unreasonable risk exists under clause (iii), the Administrator shall consider, among other factors, whether and to what extent the use of the proposed technological system will cause, increase, reduce, or eliminate emissions of any unregulated pollutants; available methods for reducing or eliminating any risk to public health, welfare, or safety which may be associated with the use of such system; and the availability of other technological systems which may be used to conform to standards under this section without causing or contributing to such unreasonable risk. The Administrator may conduct such tests and may require the owner or operator of the proposed source to conduct such tests and provide such information as is necessary to carry out clause (iii) of this subparagraph. Such requirements shall include a requirement for prompt reporting of the emission of any unregulated pollutant from a system if such pollutant was not emitted, or was emitted in significantly lesser amounts without use of such system.

(B) A waiver under this paragraph shall be granted on such terms and conditions as the Administrator determines to be necessary to assure--

(i) emissions from the source will not prevent attainment and maintenance of any national ambient air quality standards, and

(ii) proper functioning of the technological system or systems authorized.

Any such term or condition shall be treated as a standard of performance for the purposes of subsection (e) of this section and section 7413 of this title.

(C) The number of waivers granted under this paragraph with respect to a proposed technological system of continuous emission reduction shall not exceed such number as the Administrator finds necessary to ascertain whether or not such system will achieve the conditions specified in clauses (ii) and (iii) of subparagraph (A).

(D) A waiver under this paragraph shall extend to the sooner of--

(i) the date determined by the Administrator, after consultation with the owner or operator of the source, taking into consideration the design, installation, and capital cost of the technological system or systems being used, or

(ii) the date on which the Administrator determines that such system has failed to--

(I) achieve at least an equivalent continuous emission reduction to that required to be achieved under the standards of performance which would otherwise apply, or

(II) comply with the condition specified in paragraph (1)(A)(iii),

and that such failure cannot be corrected.

(E) In carrying out subparagraph (D)(i), the Administrator shall not permit any waiver for a source or portion thereof to extend beyond the date--

(i) seven years after the date on which any waiver is granted to such source or portion thereof, or

(ii) four years after the date on which such source or portion thereof commences operation,

whichever is earlier.

(F) No waiver under this subsection shall apply to any portion of a source other than the portion on which the innovative technological system or systems of continuous emission reduction is used.

(2)(A) If a waiver under paragraph (1) is terminated under clause (ii) of paragraph (1)(D), the Administrator shall grant an extension of the requirements of this section for such source for such minimum period as may be necessary to comply with the applicable standard of performance under this section. Such period shall not extend beyond the date three years from the time such waiver is terminated.

(B) An extension granted under this paragraph shall set forth emission limits and a compliance schedule containing increments of progress which require compliance with the applicable standards of performance as expeditiously as practicable and include such measures as are necessary and practicable in the interim to minimize emissions. Such schedule shall be treated as a standard of performance for purposes of subsection (e) of this section and section 7413 of this title.

CREDIT(S)

(July 14, 1955, c. 360, Title I, § 111, as added Dec. 31, 1970, Pub.L. 91-604, § 4(a), 84 Stat. 1683; amended Nov. 18, 1971, Pub.L. 92-157, Title III, § 302(f), 85 Stat. 464; Aug. 7, 1977, Pub.L. 95-95, Title I, § 109(a)-(d)(1), (e), (f), Title IV, § 401(b), 91 Stat. 697 to 703, 791; Nov. 16, 1977, Pub.L. 95-190, § 14(a)(7) to (9), 91 Stat. 1399; Nov. 9, 1978, Pub.L. 95-623, § 13(a), 92 Stat. 3457; Nov. 15, 1990, Pub.L. 101-549, Title I, § 108(e) to (g), Title III, § 302(a), (b), Title IV, § 403(a), 104 Stat. 2467, 2574, 2631.)

Notes of Decisions (120)

42 U.S.C.A. § 7411, 42 USCA § 7411
Current through P.L. 114-222. Also includes P.L. 114-224, 114-226, and 114-227.

End of Document

United States Code Annotated
Title 42. The Public Health and Welfare
Chapter 85. Air Pollution Prevention and Control (Refs & Annos)
Subchapter III. General Provisions

42 U.S.C.A. § 7607

§ 7607. Administrative proceedings and judicial review

Currentness

(a) Administrative subpenas; confidentiality; witnesses

In connection with any determination under section 7410(f) of this title, or for purposes of obtaining information under section 7521(b)(4) or 7545(c)(3) of this title, any investigation, monitoring, reporting requirement, entry, compliance inspection, or administrative enforcement proceeding under the [1] chapter (including but not limited to section 7413, section 7414, section 7420, section 7429, section 7477, section 7524, section 7525, section 7542, section 7603, or section 7606 of this title),, [2] the Administrator may issue subpenas for the attendance and testimony of witnesses and the production of relevant papers, books, and documents, and he may administer oaths. Except for emission data, upon a showing satisfactory to the Administrator by such owner or operator that such papers, books, documents, or information or particular part thereof, if made public, would divulge trade secrets or secret processes of such owner or operator, the Administrator shall consider such record, report, or information or particular portion thereof confidential in accordance with the purposes of section 1905 of Title 18, except that such paper, book, document, or information may be disclosed to other officers, employees, or authorized representatives of the United States concerned with carrying out this chapter, to persons carrying out the National Academy of Sciences' study and investigation provided for in section 7521(c) of this title, or when relevant in any proceeding under this chapter. Witnesses summoned shall be paid the same fees and mileage that are paid witnesses in the courts of the United States. In case of contumacy or refusal to obey a subpena served upon any person under this subparagraph [3], the district court of the United States for any district in which such person is found or resides or transacts business, upon application by the United States and after notice to such person, shall have jurisdiction to issue an order requiring such person to appear and give testimony before the Administrator to appear and produce papers, books, and documents before the Administrator, or both, and any failure to obey such order of the court may be punished by such court as a contempt thereof.

(b) Judicial review

(1) A petition for review of action of the Administrator in promulgating any national primary or secondary ambient air quality standard, any emission standard or requirement under section 7412 of this title, any standard of performance or requirement under section 7411 of this title,, [2] any standard under section 7521 of this title (other than a standard required to be prescribed under section 7521(b)(1) of this title), any determination under section 7521(b)(5) of this title, any control or prohibition under section 7545 of this title, any standard under section 7571 of this title, any rule issued under section 7413, 7419, or under section 7420 of this title, or any other nationally applicable regulations promulgated, or final action taken, by the Administrator under this chapter may be filed only in the United States Court of Appeals for the District of Columbia. A petition for review of the Administrator's action in approving or promulgating any implementation plan under section 7410 of this title or section 7411(d) of this title, any order under section 7411(j) of this title, under section 7412 of this title, under section 7419 of this title, or under section 7420 of this title, or his action under section 1857c-10(c)(2)(A), (B), or (C) of this title (as in effect before August 7, 1977) or under regulations thereunder, or revising regulations for enhanced monitoring and compliance certification programs under section 7414(a)(3) of this title, or any other final action of the Administrator under this chapter (including any denial or disapproval by the Administrator under subchapter I of this chapter) which is locally or regionally applicable may be filed only in the United States Court of Appeals for the appropriate circuit. Notwithstanding the preceding sentence a petition for review of any action referred to in such sentence may be filed only in the United States Court of Appeals for the District of Columbia if such action is based on a determination of nationwide scope or effect and if in taking such action the Administrator finds and publishes that such action is based on such a determination. Any petition for review under this subsection shall be filed within sixty days from the date notice of such promulgation, approval, or action appears in the Federal Register, except that if such petition is based solely on grounds arising after such sixtieth day, then any petition for review under this subsection shall be filed within sixty days after such grounds arise. The filing of a petition for reconsideration by the Administrator of any otherwise final rule or action shall not affect the finality of such rule or action for purposes of judicial review nor extend the time within which a petition for judicial review of such rule or action under this section may be filed, and shall not postpone the effectiveness of such rule or action.

(2) Action of the Administrator with respect to which review could have been obtained under paragraph (1) shall not be subject to judicial review in civil or criminal proceedings for enforcement. Where a final decision by the Administrator defers performance of any nondiscretionary statutory action to a later time, any person may challenge the deferral pursuant to paragraph (1).

(c) Additional evidence

In any judicial proceeding in which review is sought of a determination under this chapter required to be made on the record after notice and opportunity for hearing, if any party applies to the court for leave to adduce additional evidence, and shows to the satisfaction of the court that such additional evidence is material and that there were reasonable grounds for the failure to adduce such evidence in the proceeding before the Administrator, the court may order such additional evidence (and evidence in rebuttal thereof) to be taken before the Administrator, in such manner and upon such terms and conditions as to [4] the court may deem proper. The Administrator may modify his findings as to the facts, or make new findings, by reason of the additional evidence so taken and he shall file such modified or new findings, and his recommendation, if any, for the modification or setting aside of his original determination, with the return of such additional evidence.

(d) Rulemaking

(1) This subsection applies to--

(A) the promulgation or revision of any national ambient air quality standard under section 7409 of this title,

(B) the promulgation or revision of an implementation plan by the Administrator under section 7410(c) of this title,

(C) the promulgation or revision of any standard of performance under section 7411 of this title, or emission standard or limitation under section 7412(d) of this title, any standard under section 7412(f) of this title, or any regulation under section 7412(g)(1)(D) and (F) of this title, or any regulation under section 7412(m) or (n) of this title,

(D) the promulgation of any requirement for solid waste combustion under section 7429 of this title,

(E) the promulgation or revision of any regulation pertaining to any fuel or fuel additive under section 7545 of this title,

(F) the promulgation or revision of any aircraft emission standard under section 7571 of this title,

(G) the promulgation or revision of any regulation under subchapter IV-A of this chapter (relating to control of acid deposition),

(H) promulgation or revision of regulations pertaining to primary nonferrous smelter orders under section 7419 of this title (but not including the granting or denying of any such order),

(I) promulgation or revision of regulations under subchapter VI of this chapter (relating to stratosphere and ozone protection),

(J) promulgation or revision of regulations under part C of subchapter I of this chapter (relating to prevention of significant deterioration of air quality and protection of visibility),

(K) promulgation or revision of regulations under section 7521 of this title and test procedures for new motor vehicles or engines under section 7525 of this title, and the revision of a standard under section 7521(a)(3) of this title,

(L) promulgation or revision of regulations for noncompliance penalties under section 7420 of this title,

(M) promulgation or revision of any regulations promulgated under section 7541 of this title (relating to warranties and compliance by vehicles in actual use),

(N) action of the Administrator under section 7426 of this title (relating to interstate pollution abatement),

(O) the promulgation or revision of any regulation pertaining to consumer and commercial products under section 7511b(e) of this title,

(P) the promulgation or revision of any regulation pertaining to field citations under section 7413(d)(3) of this title,

(Q) the promulgation or revision of any regulation pertaining to urban buses or the clean-fuel vehicle, clean-fuel fleet, and clean fuel programs under part C of subchapter II of this chapter,

(R) the promulgation or revision of any regulation pertaining to nonroad engines or nonroad vehicles under section 7547 of this title,

(S) the promulgation or revision of any regulation relating to motor vehicle compliance program fees under section 7552 of this title,

(T) the promulgation or revision of any regulation under subchapter IV-A of this chapter (relating to acid deposition),

(U) the promulgation or revision of any regulation under section 7511b(f) of this title pertaining to marine vessels, and

(V) such other actions as the Administrator may determine.

The provisions of section 553 through 557 and section 706 of Title 5 shall not, except as expressly provided in this subsection, apply to actions to which this subsection applies. This subsection shall not apply in the case of any rule or circumstance referred to in subparagraphs (A) or (B) of subsection 553(b) of Title 5.

(2) Not later than the date of proposal of any action to which this subsection applies, the Administrator shall establish a rulemaking docket for such action (hereinafter in this subsection referred to as a "rule"). Whenever a rule applies only within a particular State, a second (identical) docket shall be simultaneously established in the appropriate regional office of the Environmental Protection Agency.

(3) In the case of any rule to which this subsection applies, notice of proposed rulemaking shall be published in the Federal Register, as provided under section 553(b) of Title 5, shall be accompanied by a statement of its basis and purpose and shall specify the period available for public comment (hereinafter referred to as the "comment period"). The notice of proposed rulemaking shall also state the docket number, the location or locations of the docket, and the times it will be open to public inspection. The statement of basis and purpose shall include a summary of--

(A) the factual data on which the proposed rule is based;

(B) the methodology used in obtaining the data and in analyzing the data; and

(C) the major legal interpretations and policy considerations underlying the proposed rule.

The statement shall also set forth or summarize and provide a reference to any pertinent findings, recommendations, and comments by the Scientific Review Committee established under section 7409(d) of this title and the National Academy of Sciences, and, if the proposal differs in any important respect from any of these recommendations, an explanation of the reasons for such differences. All data, information, and documents referred to in this paragraph on which the proposed rule relies shall be included in the docket on the date of publication of the proposed rule.

(4)(A) The rulemaking docket required under paragraph (2) shall be open for inspection by the public at reasonable times specified in the notice of proposed rulemaking. Any person may copy documents contained in the docket. The Administrator shall provide copying facilities which may be used at the expense of the person seeking copies, but the Administrator may waive or reduce such expenses in such instances as the public interest requires. Any person may request copies by mail if the person pays the expenses, including personnel costs to do the copying.

(B)(i) Promptly upon receipt by the agency, all written comments and documentary information on the proposed rule received from any person for inclusion in the docket during the comment period shall be placed in the docket. The transcript of public hearings, if any, on the proposed rule shall also be included in the docket promptly upon receipt from the person who transcribed such hearings. All documents which become available after the proposed rule has been published and which the Administrator determines are of central relevance to the rulemaking shall be placed in the docket as soon as possible after their availability.

(ii) The drafts of proposed rules submitted by the Administrator to the Office of Management and Budget for any interagency review process prior to proposal of any such rule, all documents accompanying such drafts, and all written comments thereon by other agencies and all written responses to such written comments by the Administrator shall be placed in the docket no later than the date of proposal of the rule. The drafts of the final rule submitted for such review process prior to promulgation and all such written comments thereon, all documents accompanying such drafts, and written responses thereto shall be placed in the docket no later than the date of promulgation.

(5) In promulgating a rule to which this subsection applies (i) the Administrator shall allow any person to submit written comments, data, or documentary information; (ii) the Administrator shall give interested persons an opportunity for the oral presentation of data, views, or arguments, in addition to an opportunity to make written submissions; (iii) a transcript shall be kept of any oral presentation; and (iv) the Administrator shall keep the record of such proceeding open for thirty days after completion of the proceeding to provide an opportunity for submission of rebuttal and supplementary information.

(6)(A) The promulgated rule shall be accompanied by (i) a statement of basis and purpose like that referred to in paragraph (3) with respect to a proposed rule and (ii) an explanation of the reasons for any major changes in the promulgated rule from the proposed rule.

(B) The promulgated rule shall also be accompanied by a response to each of the significant comments, criticisms, and new data submitted in written or oral presentations during the comment period.

(C) The promulgated rule may not be based (in part or whole) on any information or data which has not been placed in the docket as of the date of such promulgation.

(7)(A) The record for judicial review shall consist exclusively of the material referred to in paragraph (3), clause (i) of paragraph (4)(B), and subparagraphs (A) and (B) of paragraph (6).

(B) Only an objection to a rule or procedure which was raised with reasonable specificity during the period for public comment (including any public hearing) may be raised during judicial review. If the person raising an objection can demonstrate to the Administrator that it was impracticable to raise such objection within such time or if the grounds for such objection arose after the period for public comment (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of the rule, the Administrator shall convene a proceeding for reconsideration of the rule and provide the same procedural rights as would have been afforded had the information been available at the time the rule was proposed. If the Administrator refuses to convene such a proceeding, such person may seek review of such refusal in the United States court of appeals for the appropriate circuit (as provided in subsection (b) of this section). Such reconsideration shall not postpone the effectiveness of the rule. The effectiveness of the rule may be stayed during such reconsideration, however, by the Administrator or the court for a period not to exceed three months.

(8) The sole forum for challenging procedural determinations made by the Administrator under this subsection shall be in the United States court of appeals for the appropriate circuit (as provided in subsection (b) of this section) at the time of the substantive review of the rule. No interlocutory appeals shall be permitted with respect to such procedural determinations. In reviewing alleged procedural errors, the court may invalidate the rule only if the errors were so serious and related to matters of such central relevance to the rule that there is a substantial likelihood that the rule would have been significantly changed if such errors had not been made.

(9) In the case of review of any action of the Administrator to which this subsection applies, the court may reverse any such action found to be--

(A) arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with law;

(B) contrary to constitutional right, power, privilege, or immunity;

(C) in excess of statutory jurisdiction, authority, or limitations, or short of statutory right; or

(D) without observance of procedure required by law, if (i) such failure to observe such procedure is arbitrary or capricious, (ii) the requirement of paragraph (7)(B) has been met, and (iii) the condition of the last sentence of paragraph (8) is met.

(10) Each statutory deadline for promulgation of rules to which this subsection applies which requires promulgation less than six months after date of proposal may be extended to not more than six months after date of proposal by the Administrator upon a determination that such extension is necessary to afford the public, and the agency, adequate opportunity to carry out the purposes of this subsection.

(11) The requirements of this subsection shall take effect with respect to any rule the proposal of which occurs after ninety days after August 7, 1977.

(e) Other methods of judicial review not authorized

Nothing in this chapter shall be construed to authorize judicial review of regulations or orders of the Administrator under this chapter, except as provided in this section.

(f) Costs

In any judicial proceeding under this section, the court may award costs of litigation (including reasonable attorney and expert witness fees) whenever it determines that such award is appropriate.

(g) Stay, injunction, or similar relief in proceedings relating to noncompliance penalties

In any action respecting the promulgation of regulations under section 7420 of this title or the administration or enforcement of section 7420 of this title no court shall grant any stay, injunctive, or similar relief before final judgment by such court in such action.

(h) Public participation

It is the intent of Congress that, consistent with the policy of subchapter II of chapter 5 of Title 5, the Administrator in promulgating any regulation under this chapter, including a regulation subject to a deadline, shall ensure a reasonable period for public participation of at least 30 days, except as otherwise expressly provided in section [5] 7407(d), 7502(a), 7511(a) and (b), and 7512(a) and (b) of this title.

CREDIT(S)

(July 14, 1955, c. 360, Title III, § 307, as added Dec. 31, 1970, Pub.L. 91-604, § 12(a), 84 Stat. 1707; amended Nov. 18, 1971, Pub.L. 92-157, Title III, § 302(a), 85 Stat. 464; June 22, 1974, Pub.L. 93-319, § 6(c), 88 Stat. 259; Aug. 7, 1977, Pub.L. 95-95, Title III, §§ 303(d), 305(a), (c), (f)-(h), 91 Stat. 772, 776, 777; Nov. 16, 1977, Pub.L. 95-190, § 14(a)(79), (80), 91 Stat. 1404; Nov. 15, 1990, Pub.L. 101-549, Title I, §§ 108(p), 110(5), Title III, § 302(g), (h), Title VII, §§ 702(c), 703, 706, 707(h), 710(b), 104 Stat. 2469, 2470, 2574, 2681-2684.)

Footnotes

1 So in original. Probably should be “this”.

2 So in original.

3 So in original. Probably should be “subsection,”.

4 So in original. The word “to” probably should not appear.

5 So in original. Probably should be “sections”.

42 U.S.C.A. § 7607, 42 USCA § 7607

Current through P.L. 114-222. Also includes P.L. 114-224, 114-226, and 114-227.

United States Code Annotated
Title 42. The Public Health and Welfare
Chapter 149. National Energy Policy and Programs
Subchapter IV. Coal
Part A. Clean Coal Power Initiative

42 U.S.C.A. § 15962

§ 15962. Project criteria

Effective: December 20, 2007
Currentness

(a) In general

To be eligible to receive assistance under this part, a project shall advance efficiency, environmental performance, and cost competitiveness well beyond the level of technologies that are in commercial service or have been demonstrated on a scale that the Secretary determines is sufficient to demonstrate that commercial service is viable as of August 8, 2005.

(b) Technical criteria for Clean Coal Power Initiative

(1) Gasification projects

(A) In general

In allocating the funds made available under section 15961(a) of this title, the Secretary shall ensure that at least 70 percent of the funds are used only to fund projects on coal-based gasification technologies, including--

(i) gasification combined cycle;

(ii) gasification fuel cells and turbine combined cycle;

(iii) gasification coproduction;

(iv) hybrid gasification and combustion; and

(v) other advanced coal based technologies capable of producing a concentrated stream of carbon dioxide.

(B) Technical milestones

(i) Periodic determination

(I) In general

The Secretary shall periodically set technical milestones specifying the emission and thermal efficiency levels that coal gasification projects under this part shall be designed, and reasonably expected, to achieve.

(II) Prescriptive milestones

The technical milestones shall become more prescriptive during the period of the clean coal power initiative.

(ii) 2020 goals

The Secretary shall establish the periodic milestones so as to achieve by the year 2020 coal gasification projects able--

(I)(aa) to remove at least 99 percent of sulfur dioxide; or

(bb) to emit not more than 0.04 pound SO2 per million Btu, based on a 30-day average;

(II) to emit not more than .05 lbs of NOx per million Btu;

(III) to achieve at least 95 percent reductions in mercury emissions; and

(IV) to achieve a thermal efficiency of at least--

(aa) 50 percent for coal of more than 9,000 Btu;

(bb) 48 percent for coal of 7,000 to 9,000 Btu; and

(cc) 46 percent for coal of less than 7,000 Btu.

(2) Other projects

(A) Allocation of funds

The Secretary shall ensure that up to 30 percent of the funds made available under section 15961(a) of this title are used to fund projects other than those described in paragraph (1).

(B) Technical milestones

(i) Periodic determination

(I) In general

The Secretary shall periodically establish technical milestones specifying the emission and thermal efficiency levels that projects funded under this paragraph shall be designed, and reasonably expected, to achieve.

(II) Prescriptive milestones

The technical milestones shall become more prescriptive during the period of the clean coal power initiative.

(ii) 2020 goals

The Secretary shall set the periodic milestones so as to achieve by the year 2020 projects able--

(I) to remove at least 97 percent of sulfur dioxide;

(II) to emit no more than .08 lbs of NOx per million Btu;

(III) to achieve at least 90 percent reductions in mercury emissions; and

(IV) to achieve a thermal efficiency of at least--

(aa) 43 percent for coal of more than 9,000 Btu;

(bb) 41 percent for coal of 7,000 to 9,000 Btu; and

(cc) 39 percent for coal of less than 7,000 Btu.

(3) Consultation

Before setting the technical milestones under paragraphs (1)(B) and (2)(B), the Secretary shall consult with--

(A) the Administrator of the Environmental Protection Agency; and

(B) interested entities, including--

(i) coal producers;

(ii) industries using coal;

(iii) organizations that promote coal or advanced coal technologies;

(iv) environmental organizations;

(v) organizations representing workers; and

(vi) organizations representing consumers.

(4) Existing units

In the case of projects at units in existence on August 8, 2005, in lieu of the thermal efficiency requirements described in paragraphs (1)(B)(ii)(IV) and (2)(B)(ii)(IV), the milestones shall be designed to achieve an overall thermal design efficiency improvement, compared to the efficiency of the unit as operated, of not less than--

(A) 7 percent for coal of more than 9,000 Btu;

(B) 6 percent for coal of 7,000 to 9,000 Btu; or

(C) 4 percent for coal of less than 7,000 Btu.

(5) Administration

(A) Elevation of site

In evaluating project proposals to achieve thermal efficiency levels established under paragraphs (1)(B)(i) and (2)(B)(i) and in determining progress towards thermal efficiency milestones under paragraphs (1)(B)(ii)(IV), (2)(B)(ii)(IV), and (4), the Secretary shall take into account and make adjustments for the elevation of the site at which a project is proposed to be constructed.

(B) Applicability of milestones

In applying the thermal efficiency milestones under paragraphs (1)(B)(ii)(IV), (2)(B)(ii)(IV), and (4) to projects that separate and capture at least 50 percent of the potential emissions of carbon dioxide by a facility, the energy used for separation and capture of carbon dioxide shall not be counted in calculating the thermal efficiency.

(C) Permitted uses

In carrying out this section, the Secretary may give priority to projects that include, as part of the project--

(i) the separation or capture of carbon dioxide; or

(ii) the reduction of the demand for natural gas if deployed.

(c) Financial criteria

The Secretary shall not provide financial assistance under this part for a project unless the recipient documents to the satisfaction of the Secretary that--

(1) the recipient is financially responsible;

(2) the recipient will provide sufficient information to the Secretary to enable the Secretary to ensure that the funds are spent efficiently and effectively; and

(3) a market exists for the technology being demonstrated or applied, as evidenced by statements of interest in writing from potential purchasers of the technology.

(d) Financial assistance

The Secretary shall provide financial assistance to projects that, as determined by the Secretary--

(1) meet the requirements of subsections (a), (b), and (c) of this section; and

(2) are likely--

(A) to achieve overall cost reductions in the use of coal to generate useful forms of energy or chemical feedstocks;

(B) to improve the competitiveness of coal among various forms of energy in order to maintain a diversity of fuel choices in the United States to meet electricity generation requirements; and

(C) to demonstrate methods and equipment that are applicable to 25 percent of the electricity generating facilities, using various types of coal, that use coal as the primary feedstock as of August 8, 2005.

(e) Cost-sharing

In carrying out this part, the Secretary shall require cost sharing in accordance with section 16352 of this title.

(f) Scheduled completion of selected projects

(1) In general

In selecting a project for financial assistance under this section, the Secretary shall establish a reasonable period of time during which the owner or operator of the project shall complete the construction or demonstration phase of the project, as the Secretary determines to be appropriate.

(2) Condition of financial assistance

The Secretary shall require as a condition of receipt of any financial assistance under this part that the recipient of the assistance enter into an agreement with the Secretary not to request an extension of the time period established for the project by the Secretary under paragraph (1).

(3) Extension of time period

(A) In general

Subject to subparagraph (B), the Secretary may extend the time period established under paragraph (1) if the Secretary determines, in the sole discretion of the Secretary, that the owner or operator of the project cannot complete the construction or demonstration phase of the project within the time period due to circumstances beyond the control of the owner or operator.

(B) Limitation

The Secretary shall not extend a time period under subparagraph (A) by more than 4 years.

(g) Fee title

The Secretary may vest fee title or other property interests acquired under cost-share clean coal power initiative agreements under this part in any entity, including the United States.

(h) Data protection

For a period not exceeding 5 years after completion of the operations phase of a cooperative agreement, the Secretary may provide appropriate protections (including exemptions from subchapter II of chapter 5 of Title 5) against the dissemination of information that--

(1) results from demonstration activities carried out under the clean coal power initiative program; and

(2) would be a trade secret or commercial or financial information that is privileged or confidential if the information had been obtained from and first produced by a non-Federal party participating in a clean coal power initiative project.

(i) Applicability

No technology, or level of emission reduction, solely by reason of the use of the technology, or the achievement of the emission reduction, by 1 or more facilities receiving assistance under this Act, shall be considered to be--

(1) adequately demonstrated for purposes of section 7411 of this title;

(2) achievable for purposes of section 7479 of this title; or

(3) achievable in practice for purposes of section 7501 of this title.

CREDIT(S)

(Pub.L. 109-58, Title IV, § 402, Aug. 8, 2005, 119 Stat. 750; Pub.L. 110-140, Title VI, § 653, Dec. 19, 2007, 121 Stat. 1695.)

42 U.S.C.A. § 15962, 42 USCA § 15962
Current through P.L. 114-222. Also includes P.L. 114-224, 114-226, and 114-227.

End of Document

CHAPTER 54-17.5
LIGNITE RESEARCH, DEVELOPMENT AND MARKETING

54-17.5-01. Declaration of findings and public purpose.

The legislative assembly finds and declares that North Dakota's lignite industry produces approximately thirty million tons of lignite annually, contributing to our state's and nation's energy independence by generating electricity for more than two million people in the northern great plains region and by producing synthetic natural gas from coal that heats three hundred thousand homes and businesses in eastern states, which is equivalent to over twenty thousand barrels of oil per day. The legislative assembly further finds and declares that North Dakota's lignite industry generates over twenty-eight thousand direct and indirect jobs for North Dakota, nearly three billion dollars in annual business volume, and over one hundred three million dollars in annual tax revenue. The legislative assembly further finds and declares that it is an essential governmental function and public purpose to assist with the development and wise use of North Dakota's vast lignite resources by supporting a lignite research, development, and marketing program that promotes economic, efficient, and clean uses of lignite and products derived from lignite in order to maintain and enhance development of North Dakota lignite and its products; support educational activities relating to the lignite industry; preserve and create jobs involved in the production and utilization of North Dakota lignite; ensure economic stability, growth, and opportunity in the lignite industry; and maintain a stable and competitive tax base for our state's lignite industry for the general welfare of North Dakota. The legislative assembly further finds and declares that development of North Dakota's lignite resources must be conducted in an environmentally sound manner that protects our state's air, water, and soil resources as specified by applicable federal and state law.

54-17.5-02. Lignite research council - Compensation - Appointment of members.

The industrial commission shall consult with the lignite research council established by executive order in matters of policy affecting the administration of the lignite research fund. Section 44-03-04 does not apply to members of the council appointed by the governor.

54-17.5-03. Priority projects, processes, and activities.

In evaluating applications for funding from the lignite research fund for North Dakota's lignite research, development, and marketing program, the industrial commission and lignite research council shall give priority to those projects, processes, or activities that will preserve existing jobs and production, which will create the greatest number of new jobs and most additional lignite production and economic growth potential in coal-producing counties or those counties with recoverable coal reserves, which will attract matching private industry investment equal to at least fifty percent or more of the total cost, and which will result in development and demonstration of a marketable lignite product or products with a high level of probability of near term commercialization. For marketing applications, priority must be given to those projects, processes, or activities that develop baseline information, implement specific marketing strategies, and otherwise contribute to the effective marketing of lignite and its products. For reclamation applications, priority must be given to those projects, processes, or activities that will reduce unnecessary regulatory costs and assist in effectively reclaiming surface mined land to its original or better productivity as soon as possible. Any projects, activities, or processes selected by the commission for funding must achieve the priorities and purposes of the program, must have undergone technical review and be determined to have technical merit, must have generated matching private industry investment, and must have received a favorable lignite research council recommendation.

54-17.5-04. Industrial commission powers.

The industrial commission is hereby granted all powers necessary or appropriate to carry out and effectuate the purposes of this chapter, including the power:

1. To make grants or loans, and to provide other forms of financial assistance as necessary or appropriate, to qualified persons for research, development, and

marketing projects, processes, or activities directly related to lignite and products derived from lignite.

2. To make and execute contracts and all other instruments necessary or convenient for the performance of its powers and functions under this chapter, including the authority to contract for the administration of the lignite research, development, and marketing program.
3. To issue evidences of indebtedness as authorized in this chapter and to borrow money in an amount not to exceed six million dollars from the Bank of North Dakota for a period not to exceed five years on the terms and conditions as the Bank of North Dakota and the industrial commission may approve without the necessity of establishing or maintaining any reserve fund as otherwise required by section 54-17.5-05.
4. To receive and accept aid, grants, or contributions of money or other things of value from any source to be held, used, and applied to carry out the purposes of this chapter, subject to the conditions upon which the aid, grants, or contributions are made, including aid, grants, or contributions from any department, agency, or instrumentality of the United States for any purpose consistent with the provisions of this chapter.
5. To issue and sell evidences of indebtedness in an amount or amounts as the commission may determine, plus costs of issuance, financing, and any evidences of indebtedness funded reserve funds required by agreements with or for the benefit of holders of the evidences of indebtedness for the purpose of funding research, development, and marketing projects, processes, or activities directly related to lignite and products derived from lignite.
6. To refund and refinance its evidences of indebtedness from time to time as often as it is advantageous and in the public interest to do so, and to pledge any and all income and revenues derived by the commission under this chapter or from a project, process, or activity funded under this chapter to secure payment or redemption of the evidences of indebtedness.

54-17.5-05. Evidences of indebtedness.

1. Evidences of indebtedness issued by the industrial commission under this chapter are payable solely from:
   a. Appropriations by the legislative assembly from moneys in the lignite research fund.
   b. Revenues or income that may be received by the commission from lignite projects, processes, or activities funded under this chapter with the proceeds of the commission's evidences of indebtedness.
   c. Revenues or income received by the commission under this chapter from any source.
2. Not later than July fifteenth of each year preceding the biennial session of the legislative assembly, the industrial commission shall submit to the office of the budget a request for the amount required to be appropriated from the lignite research fund to pay debt service on outstanding evidences of indebtedness during the following biennium.
3. The evidences of indebtedness are not subject to taxation by the state or any of its political subdivisions and are not debt of the state or of any officer or agent of the state within the meaning of any statutory or constitutional provision. The evidences of indebtedness must be executed by the manual or facsimile signature of a member or members of the commission and the manual signature of a designated authenticating agent. Any evidences of indebtedness bearing the signature of a member of the commission in office at the date of signing are valid and binding for all purposes notwithstanding that before delivery the person has ceased to be a member of the commission.
4. The industrial commission shall establish and maintain a reserve fund for evidences of indebtedness issued under this chapter. There must be deposited in the reserve fund:

a. All moneys appropriated by the legislative assembly to the commission for the purpose of the reserve fund.
b. All proceeds of evidences of indebtedness issued under this chapter required to be deposited in the reserve fund by the terms of any contract between the commission and the holders of its evidences of indebtedness or any resolution of the commission concerning the proceeds of its evidences of indebtedness.
c. Any lawfully available moneys of the commission which it may determine to deposit in the reserve fund.
d. Any moneys from any other source made available to the commission for deposit in the reserve fund.

5. Moneys in the reserve fund may be expended only to pay the principal of and interest on evidences of indebtedness, including payment of any premium required to be paid when evidences of indebtedness are redeemed prior to maturity, and sinking fund installments as the same become due and payable.
6. Moneys in the reserve fund may only be withdrawn in conformity with the terms of any contract between the commission and the holders of its evidences of indebtedness or any resolution of the commission concerning the proceeds of its evidences of indebtedness.
7. The industrial commission must include in its biennial request to the office of the budget the amount, if any, necessary to restore the reserve fund to an amount equal to the amount required to be deposited in the fund by the terms of any contract or resolution described in subdivision b of subsection 4. The legislative assembly may appropriate such amount from the lignite research fund to the commission for deposit in the reserve fund. If sufficient moneys are not available in the lignite research fund, the legislative assembly may appropriate any amount necessary out of any moneys in the general fund or any special funds in the state treasury not otherwise appropriated.

54-17.5-06. Access to commission records.

1. Materials and data submitted to, or made or received by, the commission, to the extent that the commission determines the materials or data consist of trade secrets or commercial, financial, or proprietary information of individuals or entities applying to or contracting with the commission or receiving commission services under this chapter are subject to section 44-04-18.4.
2. A person or entity must file a request with the commission to have material designated as confidential under subsection 1. A request to have material designated as confidential is exempt as defined in section 44-04-17.1. The request must contain any information required by the commission, and must include at least the following:
   a. A general description of the nature of the information sought to be protected.
   b. An explanation of why the information derives independent economic value, actual or potential, from not being generally known to other persons.
   c. An explanation of why the information is not readily ascertainable by proper means by other persons.
   d. A general description of any person or entity that may obtain economic value from disclosure or use of the information, and how the person or entity may obtain this value.
   e. A description of the efforts used to maintain the secrecy of the information.
3. Any information submitted under subsection 2 is confidential. The commission shall examine the request and determine whether the information is relevant to the matter at hand and is a trade secret under the definition in section 47-25.1-01 or 44-04-18.4. If the commission determines the information is either not relevant or not a trade secret, the commission shall notify the requester and the requester may ask for the return of the information and request within ten days of the notice. If no return is sought, the information and request are a public record.
4. The names or identities of independent technical reviewers on any project or program and the names of individual lignite council members making recommendations are confidential and may not be disclosed by the commission.

REGULATIONS

Code of Federal Regulations
Title 40. Protection of Environment
Chapter I. Environmental Protection Agency (Refs & Annos)
Subchapter C. Air Programs
Part 60. Standards of Performance for New Stationary Sources (Refs & Annos)
Subpart B. Adoption and Submittal of State Plans for Designated Facilities (Refs & Annos)

40 C.F.R. § 60.22

§ 60.22 Publication of guideline documents, emission guidelines, and final compliance times.

Currentness

(a) Concurrently upon or after proposal of standards of performance for the control of a designated pollutant from affected facilities, the Administrator will publish a draft guideline document containing information pertinent to control of the designated pollutant form designated facilities. Notice of the availability of the draft guideline document will be published in the Federal Register and public comments on its contents will be invited. After consideration of public comments and upon or after promulgation of standards of performance for control of a designated pollutant from affected facilities, a final guideline document will be published and notice of its availability will be published in the Federal Register.

(b) Guideline documents published under this section will provide information for the development of State plans, such as:

(1) Information concerning known or suspected endangerment of public health or welfare caused, or contributed to, by the designated pollutant.

(2) A description of systems of emission reduction which, in the judgment of the Administrator, have been adequately demonstrated.

(3) Information on the degree of emission reduction which is achievable with each system, together with information on the costs and environmental effects of applying each system to designated facilities.

(4) Incremental periods of time normally expected to be necessary for the design, installation, and startup of identified control systems.

(5) An emission guideline that reflects the application of the best system of emission reduction (considering the cost of such reduction) that has been adequately demonstrated for designated facilities, and the time within which compliance with emission standards of equivalent stringency can be achieved. The Administrator will specify different emission guidelines or compliance times or both for different sizes, types, and classes of designated facilities when costs of control, physical limitations, geographical location, or similar factors make subcategorization appropriate.

(6) Such other available information as the Administrator determines may contribute to the formulation of State plans.

(c) Except as provided in paragraph (d)(1) of this section, the emission guidelines and compliance times referred to in paragraph (b)(5) of this section will be proposed for comment upon publication of the draft guideline document, and after consideration of comments will be promulgated in subpart C of this part with such modifications as may be appropriate.

(d)(1) If the Administrator determines that a designated pollutant may cause or contribute to endangerment of public welfare, but that adverse effects on public health have not been demonstrated, he will include the determination in the draft guideline document and in the Federal Register notice of its availability. Except as provided in paragraph (d)(2) of this section, paragraph (c) of this section shall be inapplicable in such cases.

(2) If the Administrator determines at any time on the basis of new information that a prior determination under paragraph (d)(1) of this section is incorrect or no longer correct, he will publish notice of the determination in the Federal Register, revise the guideline document as necessary under paragraph (a) of this section, and propose and promulgate emission guidelines and compliance times under paragraph (c) of this section.

Credits
[54 FR 52189, Dec. 20, 1989]

SOURCE: 36 FR 24877, Dec. 23, 1971; 40 FR 53346, Nov. 17, 1975; 50 FR 36834, Sept. 9, 1985; 52 FR 37874, Oct. 9, 1987; 53 FR 2675, Jan. 29, 1988; 57 FR 32338, July 21, 1992; 58 FR 40591, July 29, 1993; 60 FR 65384, Dec. 19, 1995; 62 FR 8328, Feb. 24, 1997; 62 FR 48379, Sept. 15, 1997; 64 FR 7463, Feb. 12, 1999; 65 FR 78275, Dec. 14, 2000; 72 FR 59204, Oct. 19, 2007, unless otherwise noted.

AUTHORITY: 42 U.S.C. 7401 et seq.

Current through October 6, 2016; 81 FR 69658.

End of Document

Code of Federal Regulations
Title 40. Protection of Environment
Chapter I. Environmental Protection Agency (Refs & Annos)
Subchapter C. Air Programs
Part 60. Standards of Performance for New Stationary Sources (Refs & Annos)
Subpart DA. Standards of Performance for Electric Utility Steam Generating (Refs & Annos)

40 C.F.R. § 60.44Da

§ 60.44Da Standards for nitrogen oxides (NO_X).

Effective: April 16, 2012
Currentness

(a) Except as provided in paragraph (h) of this section, on and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction, reconstruction, or modification commenced before July 10, 1997 any gases that contain NO_X (expressed as NO_2) in excess of the applicable emissions limit in paragraphs (a)(1) and (2) of this section.

(1) The owner or operator shall not cause to be discharged into the atmosphere any gases that contain NO_X in excess of the emissions limit listed in the following table as applicable to the fuel type combusted and as determined on a 30–boiler operating day rolling average basis.

Fuel type	**Emission limit for heat input**	
	ng/J	**lb/MMBtu**
Gaseous fuels:		
Coal-derived fuels	210	0.50
All other fuels	86	0.20
Liquid fuels:		
Coal-derived fuels	210	0.50
Shale oil	210	0.50
All other fuels	130	0.30
Solid fuels:		
Coal-derived fuels	210	0.50
Any fuel containing more than 25%, by weight, coal refuse	([1])	([1])

Any fuel containing more than 25%, by weight, lignite if the lignite is mined in North Dakota, South Dakota, or Montana, and is combusted in a slag tap furnace [2]	340	0.80
Any fuel containing more than 25%, by weight, lignite not subject to the 340 ng/J heat input emission limit [2]	260	0.60
Subbituminous coal..	210	0.50
Bituminous coal..	260	0.60
Anthracite coal..	260	0.60
All other fuels..	260	0.60

(2) When two or more fuels are combusted simultaneously in an affected facility, the applicable emissions limit (E_n) is determined by proration using the following formula:

$$En = \frac{(86w + 130x + 210y + 260z + 340v)}{100}$$

Where:

En = Applicable NO_X emissions limit when multiple fuels are combusted simultaneously (ng/J heat input);

w = Percentage of total heat input derived from the combustion of fuels subject to the 86 ng/J heat input standard;

x = Percentage of total heat input derived from the combustion of fuels subject to the 130 ng/J heat input standard;

y = Percentage of total heat input derived from the combustion of fuels subject to the 210 ng/J heat input standard;

z = Percentage of total heat input derived from the combustion of fuels subject to the 260 ng/J heat input standard; and

v = Percentage of total heat input delivered from the combustion of fuels subject to the 340 ng/J heat input standard.

(b) [Reserved]

(c) [Reserved]

(d) Except as provided in paragraph (h) of this section, on and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification after July 9, 1997, but before March 1, 2005, shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO_X (expressed as NO_2) in excess of the applicable emissions limit specified in paragraphs (d)(1) and (2) of this section as determined on a 30–boiler operating day rolling average basis.

(1) For an affected facility which commenced construction, any gases that contain NO_X in excess of 200 ng/J (1.6 lb/MWh) gross energy output.

(2) For an affected facility which commenced reconstruction, any gases that contain NO_X in excess of 65 ng/J (0.15 lb/MMBtu) heat input.

(e) Except as provided in paragraphs (f) and (h) of this section, on and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification after February 28, 2005 but before May 4, 2011, shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO_X (expressed as NO_2) in excess of the applicable emissions limit specified in paragraphs (e)(1) through (3) of this section as determined on a 30–boiler operating day rolling average basis.

(1) For an affected facility which commenced construction, any gases that contain NO_X in excess of 130 ng/J (1.0 lb/MWh) gross energy output.

(2) For an affected facility which commenced reconstruction, any gases that contain NO_X in excess of either:

(i) 130 ng/J (1.0 lb/MWh) gross energy output; or

(ii) 47 ng/J (0.11 lb/MMBtu) heat input.

(3) For an affected facility which commenced modification, any gases that contain NO_X in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output; or

(ii) 65 ng/J (0.15 lb/MMBtu) heat input.

(f) On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, the owner or operator of an IGCC electric utility steam generating unit subject to the provisions of this subpart and for which construction, reconstruction, or modification commenced after February 28, 2005 but before May 4, 2011, shall meet the requirements specified in paragraphs (f)(1) through (3) of this section.

(1) Except as provided for in paragraphs (f)(2) and (3) of this section, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain NO_X (expressed as NO_2) in excess of 130 ng/J (1.0 lb/MWh) gross energy output.

(2) When burning liquid fuel exclusively or in combination with solid-derived fuel such that the liquid fuel contributes 50 percent or more of the total heat input to the combined cycle combustion turbine, the owner or

operator shall not cause to be discharged into the atmosphere any gases that contain NO_X (expressed as NO_2) in excess of 190 ng/J (1.5 lb/MWh) gross energy output.

(3) In cases when during a 30–boiler operating day rolling average compliance period liquid fuel is burned in such a manner to meet the conditions in paragraph (f)(2) of this section for only a portion of the clock hours in the 30–day compliance period, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain NO_X (expressed as NO_2) in excess of the computed weighted-average emissions limit based on the proportion of gross energy output (in MWh) generated during the compliance period for each of emissions limits in paragraphs (f)(1) and (2) of this section.

(g) Except as provided in paragraphs (h) of this section and § 60.45Da, on and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification after May 3, 2011, shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO_X (expressed as NO_2) in excess of the applicable emissions limit specified in paragraphs (g)(1) through (3) of this section.

(1) For an affected facility which commenced construction or reconstruction, any gases that contain NO_X in excess of either:

(i) 88 ng/J (0.70 lb/MWh) gross energy output; or

(ii) 95 ng/J (0.76 lb/MWh) net energy output.

(2) For an affected facility which commenced construction or reconstruction and that burns 75 percent or more coal refuse (by heat input) on a 12–month rolling average basis, any gases that contain NO_X in excess of either:

(i) 110 ng/J (0.85 lb/MWh) gross energy output; or

(ii) 120 ng/J (0.92 lb/MWh) net energy output.

(3) For an affected facility which commenced modification, any gases that contain NO_X in excess of 140 ng/J (1.1 lb/MWh) gross energy output.

(h) The NO_X emissions limits under this section do not apply to an owner or operator of an affected facility which is operating under a commercial demonstration permit issued by the Administrator in accordance with the provisions of § 60.47Da.

Credits
[77 FR 9451, Feb. 16, 2012]

SOURCE: 36 FR 24877, Dec. 23, 1971; 50 FR 36834, Sept. 9, 1985; 52 FR 37874, Oct. 9, 1987; 53 FR 2675, Jan. 29, 1988; 57 FR 32338, July 21, 1992; 58 FR 40591, July 29, 1993; 60 FR 65384, Dec. 19, 1995; 62 FR 8328, Feb. 24, 1997; 62 FR 48379, Sept. 15, 1997; 64 FR 7463, Feb. 12, 1999; 65 FR 78275, Dec. 14, 2000; 72 FR 32722, June 13, 2007; 72 FR 59204, Oct. 19, 2007; 77 FR 9448, Feb. 16, 2012, unless otherwise noted.

AUTHORITY: 42 U.S.C. 7401 et seq.

Notes of Decisions (34)

Current through October 6, 2016; 81 FR 69658.

Footnotes

1 Exempt from NO^X standards and NO^X monitoring requirements.

2 Any fuel containing less than 25%, by weight, lignite is not prorated but its percentage is added to the percentage of the predominant fuel.

End of Document

XVI. Statutory Authority

The statutory authority for this action is provided by sections 111, 301, 302, and 307(d)(1)(C) of the CAA as amended (42 U.S.C. 7411, 7601, 7602, 7607(d)(1)(C)). This action is also subject to section 307(d) of the CAA (42 U.S.C. 7607(d)).

List of Subjects

40 CFR Part 60

Environmental protection, Administrative practice and procedure, Air pollution control, Incorporation by reference, Intergovernmental relations, Reporting and recordkeeping requirements.

40 CFR Part 70

Environmental protection, Administrative practice and procedure, Air pollution control, Intergovernmental relations, Reporting and recordkeeping requirements.

40 CFR Part 71

Environmental protection, Administrative practice and procedure, Air pollution control, Reporting and recordkeeping requirements.

40 CFR Part 98

Environmental protection, Greenhouse gases and monitoring, Reporting and recordkeeping requirements.

Dated: August 3, 2015.

Gina McCarthy,

Administrator.

For the reasons stated in the preamble, title 40, chapter I, parts 60, 70, 71, and 98 of the Code of the Federal Regulations are amended as follows:

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

■ 1. The authority citation for part 60 continues to read as follows:

Authority: 42 U.S.C. 7401 *et seq.*

■ 2. Section 60.17 is amended by:
■ a. Redesignating paragraphs (d) through (t) as paragraphs (e) through (u) and adding paragraph (d);
■ b. In newly redesignated paragraph (g), further redesignating paragraph (g)(15) as paragraph (g)(17) and adding paragraphs (g)(15) and (16);
■ c. In newly redesignated paragraph (h), revising paragraphs (h)(37), (42), (46), (138), (187), and (190); and
■ c. In newly redesignated paragraph (m), further redesignating paragraph (m)(1) as paragraph (m)(2) and adding paragraph (m)(1).

The revisions and additions read as follows:

§ 60.17 Incorporations by reference.

* * * * *

(d) The following material is available for purchase from the American National Standards Institute (ANSI), 25 W. 43rd Street, 4th Floor, New York, NY 10036, Telephone (212) 642–4980, and is also available at the following Web site: *http://www.ansi.org.*

(1) ANSI No. C12.20–2010 American National Standard for Electricity Meters—0.2 and 0.5 Accuracy Classes (Approved August 31, 2010), IBR approved for § 60.5535(d).

(2) [Reserved]

* * * * *

(g) * * *

(15) ASME PTC 22–2014, Gas Turbines: Performance Test Codes, (Issued December 31, 2014), IBR approved for § 60.5580.

(16) ASME PTC 46–1996, Performance Test Code on Overall Plant Performance, (Issued October 15, 1997), IBR approved for § 60.5580.

* * * * *

(h) * * *

(37) ASTM D388–99 (Reapproved 2004) $^{\varepsilon 1}$ Standard Classification of Coals by Rank, IBR approved for §§ 60.41, 60.45(f), 60.41Da, 60.41b, 60.41c, 60.251, and 60.5580.

* * * * *

(42) ASTM D396–98, Standard Specification for Fuel Oils, IBR approved for §§ 60.41b, 60.41c, 60.111(b), 60.111a(b), and 60.5580.

* * * * *

(46) ASTM D975–08a, Standard Specification for Diesel Fuel Oils, IBR approved for §§ 60.41b 60.41c, and 60.5580.

* * * * *

(138) ASTM D3699–08, Standard Specification for Kerosine, including Appendix X1, (Approved September 1, 2008), IBR approved for §§ 60.41b, 60.41c, and 60.5580.

* * * * *

(187) ASTM D6751–11b, Standard Specification for Biodiesel Fuel Blend Stock (B100) for Middle Distillate Fuels, including Appendices X1 through X3, (Approved July 15, 2011), IBR approved for §§ 60.41b, 60.41c, and 60.5580.

* * * * *

(190) ASTM D7467–10, Standard Specification for Diesel Fuel Oil, Biodiesel Blend (B6 to B20), including Appendices X1 through X3, (Approved August 1, 2010), IBR approved for §§ 60.41b, 60.41c, and 60.5580.

* * * * *

(m) * * *

(1) ISO 2314:2009(E), Gas turbines–Acceptance tests, Third edition (December 15, 2009), IBR approved for § 60.5580.

* * * * *

■ 3. Part 60 is amended by adding subpart TTTT to read as follows:

Subpart TTTT—Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units

Applicability

§ 60.5508 What is the purpose of this subpart?

This subpart establishes emission standards and compliance schedules for the control of greenhouse gas (GHG) emissions from a steam generating unit, IGCC, or a stationary combustion turbine that commences construction after January 8, 2014 or commences modification or reconstruction after June 18, 2014. An affected steam generating unit, IGCC, or stationary combustion turbine shall, for the purposes of this subpart, be referred to as an affected EGU.

§ 60.5509 Am I subject to this subpart?

(a) Except as provided for in paragraph (b) of this section, the GHG standards included in this subpart apply to any steam generating unit, IGCC, or stationary combustion turbine that commenced construction after January 8, 2014 or commenced reconstruction after June 18, 2014 that meets the relevant applicability conditions in paragraphs (a)(1) and (2) of this section. The GHG standards included in this subpart also apply to any steam generating unit or IGCC that commenced modification after June 18, 2014 that meets the relevant applicability conditions in paragraphs (a)(1) and (2) of this section.

(1) Has a base load rating greater than 260 GJ/h (250 MMBtu/h) of fossil fuel (either alone or in combination with any other fuel); and

(2) Serves a generator or generators capable of selling greater than 25 MW of electricity to a utility power distribution system.

(b) You are not subject to the requirements of this subpart if your affected EGU meets any of the conditions specified in paragraphs (b)(1) through (10) of this section.

(1) Your EGU is a steam generating unit or IGCC that is currently and always has been subject to a federally enforceable permit condition limiting annual net-electric sales to no more than one-third of its potential electric output or 219,000 MWh, whichever is greater.

(2) Your EGU is capable of combusting 50 percent or more non-fossil fuel and is also subject to a federally enforceable permit condition limiting the annual capacity factor for all fossil fuels combined of 10 percent (0.10) or less.

(3) Your EGU is a combined heat and power unit that is subject to a federally enforceable permit condition limiting annual net-electric sales to no more than either 219,000 MWh or the product of the design efficiency and the potential electric output, whichever is greater.

(4) Your EGU serves a generator along with other steam generating unit(s), IGCC, or stationary combustion turbine(s) where the effective generation capacity (determined based on a prorated output of the base load rating of each steam generating unit, IGCC, or stationary combustion turbine) is 25 MW or less.

(5) Your EGU is a municipal waste combustor that is subject to subpart Eb of this part.

(6) Your EGU is a commercial or industrial solid waste incineration unit that is subject to subpart CCCC of this part.

(7) Your EGU is a steam generating unit or IGCC that undergoes a modification resulting in an hourly increase in CO_2 emissions (mass per hour) of 10 percent or less (2 significant figures). Modified units that are not subject to the requirements of this subpart pursuant to this subsection continue to be existing units under section 111 with respect to CO_2 emissions standards.

(8) Your EGU is a stationary combustion turbine that is not capable of combusting natural gas (*e.g.,* not connected to a natural gas pipeline).

(9) The proposed Washington County EGU project described in Air Quality Permit No. 4911–303–0051–P–01–0 issued by the Georgia Department of Natural Resources, Environmental Protection Division, Air Protection Branch, effective April 8, 2010, provided that construction had not commenced for NSPS purposes as of January 8, 2014.

(10) The proposed Holcomb EGU project described in Air Emission Source Construction Permit 0550023 issued by the Kansas Department of Health and Environment, Division of Environment, effective December 16, 2010, provided that construction had not commenced for NSPS purposes as of January 8, 2014.

Emission Standards

§ 60.5515 Which pollutants are regulated by this subpart?

(a) The pollutants regulated by this subpart are greenhouse gases. The greenhouse gas standard in this subpart is in the form of a limitation on emission of carbon dioxide.

(b) *PSD and title V thresholds for greenhouse gases.* (1) For the purposes of 40 CFR 51.166(b)(49)(ii), with respect to GHG emissions from affected facilities, the ‘‘pollutant that is subject to the standard promulgated under section 111 of the Act’’ shall be considered to be the pollutant that otherwise is subject to regulation under the Act as defined in § 51.166(b)(48) of this chapter and in any SIP approved by the EPA that is interpreted to incorporate, or specifically incorporates, § 51.166(b)(48).

(2) For the purposes of 40 CFR 52.21(b)(50)(ii), with respect to GHG emissions from affected facilities, the ‘‘pollutant that is subject to the standard promulgated under section 111 of the Act’’ shall be considered to be the pollutant that otherwise is subject to regulation under the Act as defined in § 52.21(b)(49) of this chapter.

(3) For the purposes of 40 CFR 70.2, with respect to greenhouse gas emissions from affected facilities, the ‘‘pollutant that is subject to any standard promulgated under section 111 of the Act’’ shall be considered to be the pollutant that otherwise is ‘‘subject to regulation’’ as defined in 40 CFR 70.2.

(4) For the purposes of 40 CFR 71.2, with respect to greenhouse gas emissions from affected facilities, the ‘‘pollutant that is subject to any standard promulgated under section 111 of the Act’’ shall be considered to be the pollutant that otherwise is ‘‘subject to regulation’’ as defined in 40 CFR 71.2.

§ 60.5520 What CO_2 emission standard must I meet?

(a) For each affected EGU subject to this subpart, you must not discharge from the affected EGU any gases that contain CO_2 in excess of the applicable CO_2 emission standard specified in Table 1 or 2 of this subpart, consistent with paragraphs (b), (c), and (d) of this section, as applicable.

(b) Except as specified in paragraphs (c) and (d) of this section, you must comply with the applicable gross energy output standard, and your operating permit must include monitoring, recordkeeping, and reporting methodologies based on the applicable gross energy output standard. For the remainder of this subpart (for sources that do not qualify under paragraphs (c) and (d) of this section), where the term ‘‘gross or net energy output’’ is used, the term that applies to you is ‘‘gross energy output.’’

(c) As an alternate to meeting the requirements in paragraph (b) of this section, an owner or operator of a stationary combustion turbine may petition the Administrator in writing to comply with the alternate applicable net energy output standard. If the Administrator grants the petition, beginning on the date the Administrator grants the petition, the affected EGU must comply with the applicable net energy output-based standard included in this subpart. Your operating permit must include monitoring, recordkeeping, and reporting methodologies based on the applicable net energy output standard. For the remainder of this subpart, where the term ‘‘gross or net energy output’’ is used, the term that applies to you is ‘‘net energy output.’’ Owners or operators complying with the net output-based standard must petition the Administrator to switch back to complying with the gross energy output-based standard.

(d) Stationary combustion turbines subject to a heat input-based standard in Table 2 of this subpart that are only permitted to burn one or more uniform fuels, as described in paragraph (d)(1) of this section, are only subject to the monitoring requirements in paragraph (d)(1). All other stationary combustion turbines subject to a heat input based standard in Table 2 are subject to the requirements in paragraph (d)(2) of this section.

(1) Stationary combustion turbines that are only permitted to burn fuels with a consistent chemical composition (*i.e.,* uniform fuels) that result in a consistent emission rate of 160 lb CO_2/MMBtu or less are not subject to any monitoring or reporting requirements under this subpart. These fuels include, but are not limited to, natural gas, methane, butane, butylene, ethane, ethylene, propane, naphtha, propylene, jet fuel kerosene, No. 1 fuel oil, No. 2 fuel oil, and biodiesel. Stationary combustion turbines qualifying under this paragraph are only required to maintain purchase records for permitted fuels.

(2) Stationary combustion turbines permitted to burn fuels that do not have a consistent chemical composition or that do not have an emission rate of 160 lb CO_2/MMBtu or less (*e.g.,* non-uniform fuels such as residual oil and non-jet fuel kerosene) must follow the monitoring, recordkeeping, and reporting requirements necessary to complete the heat input-based calculations under this subpart.

General Compliance Requirements

§ 60.5525 What are my general requirements for complying with this subpart?

Combustion turbines qualifying under § 60.5520(d)(1) are not subject to any requirements in this section other than the requirement to maintain fuel purchase records for permitted fuel(s). For all other affected sources, compliance with the applicable CO_2 emission standard of this subpart shall be determined on a 12-operating-month rolling average basis. See Table 1 or 2 of this subpart for the applicable CO_2 emission standards.

(a) You must be in compliance with the emission standards in this subpart that apply to your affected EGU at all times. However, you must determine compliance with the emission standards only at the end of the applicable operating month, as provided in paragraph (a)(1) of this section.

(1) For each affected EGU subject to a CO_2 emissions standard based on a 12-operating-month rolling average, you must determine compliance monthly by calculating the average CO_2 emissions rate for the affected EGU at the end of the initial and each subsequent 12-operating-month period.

(2) Consistent with § 60.5520(d)(2), if your affected stationary combustion turbine is subject to an input-based CO_2 emissions standard, you must determine the total heat input in million Btus (MMBtu) from natural gas ($HTIP_{ng}$) and the total heat input from all other fuels combined ($HTIP_o$) using one of the methods under § 60.5535(d)(2). You must then use the following equation to determine the applicable emissions standard during the compliance period:

$$CO_2 \text{ emission standard} = \frac{(120 \text{ x } \mathrm{HTIP}_{ng}) + (160 \text{ x } \mathrm{HTIP}_o)}{\mathrm{HTIP}_{ng} + \mathrm{HTIP}_o} \quad \text{(Eq. 1)}$$

Where:

CO_2 emission standard = the emission standard during the compliance period in units of lb/MMBtu.
$HTIP_{ng}$ = the heat input in MMBtu from natural gas.
$HTIP_o$ = the heat input in MMBtu from all fuels other than natural gas.
120 = allowable emission rate in lb of CO_2/MMBtu for heat input derived from natural gas.
160 = allowable emission rate in lb of CO_2/MMBtu for heat input derived from all fuels other than natural gas.

(b) At all times you must operate and maintain each affected EGU, including associated equipment and monitors, in a manner consistent with safety and good air pollution control practice. The Administrator will determine if you are using consistent operation and maintenance procedures based on information available to the Administrator that may include, but is not limited to, fuel use records, monitoring results, review of operation and maintenance procedures and records, review of reports required by this subpart, and inspection of the EGU.

(c) Within 30 days after the end of the initial compliance period (*i.e.,* no more than 30 days after the first 12-operating-month compliance period), you must make an initial compliance determination for your affected EGU(s) with respect to the applicable emissions standard in Table 1 or 2 of this subpart, in accordance with the requirements in this subpart. The first operating month included in the initial 12-operating-month compliance period shall be determined as follows:

(1) For an affected EGU that commences commercial operation (as defined in § 72.2 of this chapter) on or after October 23, 2015, the first month of the initial compliance period shall be the first operating month (as defined in § 60.5580) after the calendar month in which emissions reporting is required to begin under:

(i) Section 63.5555(c)(3)(i), for units subject to the Acid Rain Program; or

(ii) Section 63.5555(c)(3)(ii)(A), for units that are not in the Acid Rain Program.

(2) For an affected EGU that has commenced COMMERCIAL operation (as defined in § 72.2 of this chapter) prior to October 23, 2015:

(i) If the date on which emissions reporting is required to begin under § 75.64(a) of this chapter has passed prior to October 23, 2015, emissions reporting shall begin according to § 63.5555(c)(3)(i) (for Acid Rain program units), or according to § 63.5555(c)(3)(ii)(B) (for units that are not subject to the Acid Rain Program). The first month of the initial compliance period shall be the first operating month (as defined in § 60.5580) after the calendar month in which the rule becomes effective; or

(ii) If the date on which emissions reporting is required to begin under § 75.64(a) of this chapter occurs on or after October 23, 2015, then the first month of the initial compliance period shall be the first operating month (as defined in § 60.5580) after the calendar month in which emissions reporting is required to begin under § 63.5555(c)(3)(ii)(A).

(3) For a modified or reconstructed EGU that becomes subject to this subpart, the first month of the initial compliance period shall be the first operating month (as defined in § 60.5580) after the calendar month in which emissions reporting is required to begin under § 63.5555(c)(3)(iii).

Monitoring and Compliance Determination Procedures

§ 60.5535 How do I monitor and collect data to demonstrate compliance?

(a) Combustion turbines qualifying under § 60.5520(d)(1) are not subject to any requirements in this section other than the requirement to maintain fuel purchase records for permitted fuel(s). If your combustion turbine uses non-uniform fuels as specified under § 60.5520(d)(2), you must monitor heat input in accordance with paragraph (c)(1) of this section, and you must monitor CO_2 emissions in accordance with either paragraph (b), (c)(2), or (c)(5) of this section. For all other affected sources, you must prepare a monitoring plan to quantify the hourly CO_2 mass emission rate (tons/h), in accordance with the applicable provisions in § 75.53(g) and (h) of this chapter. The electronic portion of the monitoring plan must be submitted using the ECMPS Client Tool and must be in place prior to reporting emissions data and/or the results of monitoring system certification tests under this subpart. The monitoring plan must be updated as necessary. Monitoring plan submittals must be made by the Designated Representative (DR), the Alternate DR, or a delegated agent of the DR (see § 60.5555(c)).

(b) You must determine the hourly CO_2 mass emissions in kilograms (kg) from your affected EGU(s) according to paragraphs (b)(1) through (5) of this section, or, if applicable, as provided in paragraph (c) of this section.

(1) For an affected coal-fired EGU or for an IGCC unit you must, and for all other affected EGUs you may, install, certify, operate, maintain, and calibrate a CO_2 continuous emission monitoring system (CEMS) to directly measure and record hourly average CO_2 concentrations in the affected EGU exhaust gases emitted to the atmosphere, and a flow monitoring system to measure hourly average stack gas flow rates, according to § 75.10(a)(3)(i) of this chapter. As an alternative to direct measurement of CO_2 concentration, provided that your EGU does not use carbon separation (*e.g.,* carbon capture and storage), you may use data from a certified oxygen (O_2) monitor to calculate hourly average CO_2 concentrations, in accordance with § 75.10(a)(3)(iii) of this chapter. If you measure CO_2 concentration on a dry basis, you must also install, certify, operate, maintain, and calibrate a continuous moisture monitoring system, according to § 75.11(b) of this chapter. Alternatively, you may either use an appropriate fuel-specific default moisture value from § 75.11(b) or submit a petition to the Administrator under § 75.66 of this chapter for a site-specific default moisture value.

(2) For each continuous monitoring system that you use to determine the CO_2 mass emissions, you must meet the applicable certification and quality assurance procedures in § 75.20 of this chapter and appendices A and B to part 75 of this chapter.

(3) You must use only unadjusted exhaust gas volumetric flow rates to determine the hourly CO_2 mass emissions rate from the affected EGU; you must not apply the bias adjustment factors described in Section 7.6.5 of appendix A to part 75 of this chapter to the exhaust gas flow rate data.

(4) You must select an appropriate reference method to setup (characterize) the flow monitor and to perform the on-going RATAs, in accordance with part 75 of this chapter. If you use a Type-S pitot tube or a pitot tube assembly for the flow RATAs, you must calibrate the pitot tube or pitot tube assembly; you may not use the 0.84 default Type-S pitot tube coefficient specified in Method 2.

(5) Calculate the hourly CO_2 mass emissions (kg) as described in paragraphs (b)(5)(i) through (iv) of this section. Perform this calculation only for ''valid operating hours'', as defined in § 60.5540(a)(1).

(i) Begin with the hourly CO_2 mass emission rate (tons/h), obtained either from Equation F–11 in Appendix F to part 75 of this chapter (if CO_2 concentration is measured on a wet basis), or by following the procedure in section 4.2 of appendix F to part 75 of this chapter (if CO_2 concentration is measured on a dry basis).

(ii) Next, multiply each hourly CO_2 mass emission rate by the EGU or stack operating time in hours (as defined in § 72.2 of this chapter), to convert it to tons of CO_2.

(iii) Finally, multiply the result from paragraph (b)(5)(ii) of this section by 909.1 to convert it from tons of CO_2 to kg. Round off to the nearest kg.

(iv) The hourly CO_2 tons/h values and EGU (or stack) operating times used to calculate CO_2 mass emissions are required to be recorded under § 75.57(e) of this chapter and must be reported electronically under § 75.64(a)(6) of this chapter. You must use these data to calculate the hourly CO_2 mass emissions.

(c) If your affected EGU exclusively combusts liquid fuel and/or gaseous fuel, as an alternative to complying with paragraph (b) of this section, you may determine the hourly CO_2 mass emissions according to paragraphs (c)(1) through (4) of this section. If you use non-uniform fuels as specified in § 60.5520(d)(2), you may determine CO_2 mass emissions during the compliance period according to paragraph (c)(5) of this section.

(1) If you are subject to an output-based standard and you do not install CEMS in accordance with paragraph (b) of this section, you must implement the applicable procedures in appendix D to part 75 of this chapter to determine hourly EGU heat input rates (MMBtu/h), based on hourly measurements of fuel flow rate and periodic determinations of the gross calorific value (GCV) of each fuel combusted.

(2) For each measured hourly heat input rate, use Equation G–4 in appendix G to part 75 of this chapter to calculate the hourly CO_2 mass emission rate (tons/h). You may determine site-specific carbon-based F-factors (F_c) using Equation F–7b in section 3.3.6 of appendix F to part 75 of this chapter, and you may use these F_c values in the emissions calculations instead of using the default F_c values in the Equation G–4 nomenclature.

(3) For each ''valid operating hour'' (as defined in § 60.5540(a)(1), multiply the hourly tons/h CO_2 mass emission rate from paragraph (c)(2) of this section by the EGU or stack operating time in hours (as defined in § 72.2 of this chapter), to convert it to tons of CO_2. Then, multiply the result by 909.1 to convert from tons of CO_2 to kg. Round off to the nearest two significant figures.

(4) The hourly CO_2 tons/h values and EGU (or stack) operating times used to calculate CO_2 mass emissions are required to be recorded under § 75.57(e) of this chapter and must be reported electronically under § 75.64(a)(6) of this chapter. You must use these data to calculate the hourly CO_2 mass emissions.

(5) If you operate a combustion turbine firing non-uniform fuels, as an alternative to following paragraphs (c)(1) through (4) of this section, you may determine CO_2 emissions during the compliance period using one of the following methods:

(i) Units firing fuel gas may determine the heat input during the compliance period following the procedure under § 60.107a(d) and convert this heat input to CO_2 emissions using Equation G–4 in appendix G to part 75 of this chapter.

(ii) You may use the procedure for determining CO_2 emissions during the compliance period based on the use of the Tier 3 methodology under § 98.33(a)(3) of this chapter.

(d) Consistent with § 60.5520, you must determine the basis of the emissions standard that applies to your affected source in accordance with either paragraph (d)(1) or (2) of this section, as applicable:

(1) If you operate a source subject to an emissions standard established on an output basis (*e.g.,* lb of CO_2 per gross or net MWh of energy output), you must install, calibrate, maintain, and operate a sufficient number of watt meters to continuously measure and record the hourly gross electric output or net electric output, as applicable, from the affected EGU(s). These measurements must be performed using 0.2 class electricity metering instrumentation and calibration procedures as specified under ANSI Standards No. C12.20 (incorporated by reference, see § 60.17). For a combined heat and power (CHP) EGU, as defined in § 60.5580, you must also install, calibrate, maintain, and operate meters to continuously (*i.e.,* hour-by-hour) determine and record the total useful thermal output. For process steam applications, you will need to install, calibrate, maintain, and operate meters to continuously determine and record the hourly steam flow rate, temperature, and pressure. Your plan shall ensure that you install, calibrate, maintain, and operate meters to record each component of the determination, hour-by-hour.

(2) If you operate a source subject to an emissions standard established on a heat-input basis (*e.g.,* lb CO_2/MMBtu) and your affected source uses non-uniform heating value fuels as delineated under § 60.5520(d), you must determine the total heat input for each fuel fired during the compliance period in accordance with one of the following procedures:

(i) Appendix D to part 75 of this chapter;

(ii) The procedures for monitoring heat input under § 60.107a(d);

(iii) If you monitor CO_2 emissions in accordance with the Tier 3 methodology under § 98.33(a)(3) of this chapter, you may convert your CO_2 emissions to heat input using the appropriate emission factor in Table C–1 of part 98 of this chapter. If your fuel is not listed in Table C–1, you must determine a fuel-specific carbon-based F-factor (F_c) in accordance with section 12.3.2 of EPA Method 19 of appendix A–7 to this part, and you must convert your CO_2 emissions to heat input using Equation G–4 in appendix G to part 75 of this chapter.

(e) Consistent with § 60.5520, if two or more affected EGUs serve a common electric generator, you must apportion the combined hourly gross or net energy output to the individual affected EGUs according to the fraction of the total steam load contributed by each EGU. Alternatively, if the EGUs are identical, you may apportion the combined hourly gross or net electrical load to the individual EGUs according to the fraction of the total heat input contributed by each EGU.

(f) In accordance with §§ 60.13(g) and 60.5520, if two or more affected EGUs that implement the continuous emission monitoring provisions in paragraph (b) of this section share a common exhaust gas stack and are subject to the same emissions standard in Table 1 or 2 of this subpart, you may monitor the hourly CO_2 mass emissions at the common stack in lieu of monitoring each EGU separately. If you choose this option, the hourly gross or net energy output (electric, thermal, and/or mechanical, as applicable) must be the sum of the hourly loads for the individual affected EGUs and you must express the operating time as ''stack operating hours'' (as defined in § 72.2 of this chapter). If you attain compliance with the applicable emissions standard in § 60.5520 at the common stack, each affected EGU sharing the stack is in compliance.

(g) In accordance with §§ 60.13(g) and 60.5520 if the exhaust gases from an affected EGU that implements the continuous emission monitoring provisions in paragraph (b) of this section are emitted to the atmosphere through multiple stacks (or if the exhaust gases are routed to a common stack through multiple ducts and you elect to monitor in the ducts), you must monitor the hourly CO_2 mass emissions and the ''stack operating time'' (as defined in § 72.2 of this chapter) at each stack or duct separately. In this case, you must determine compliance with the applicable emissions standard in Table 1 or 2 of this subpart by summing the CO_2 mass emissions measured at the individual stacks or ducts and dividing by the total gross or net energy output for the affected EGU.

§ 60.5540 How do I demonstrate compliance with my CO_2 emissions standard and determine excess emissions?

(a) In accordance with § 60.5520, if you are subject to an output-based emission standard or you burn non-uniform fuels as specified in § 60.5520(d)(2), you must demonstrate compliance with the applicable CO_2 emission standard in Table 1 or 2 of this subpart as required in this section. For the initial and each subsequent 12-operating-month rolling average compliance period, you must follow the procedures in paragraphs (a)(1) through (7) of this section to calculate the CO_2 mass emissions rate for your affected EGU(s) in units of the applicable emissions standard (*i.e.,* either kg/MWh or lb/MMBtu). You must use the hourly CO_2 mass emissions calculated under § 60.5535(b) or (c), as applicable, and either the generating load data from § 60.5535(d)(1) for output-based calculations or the heat input data from § 60.5535(d)(2) for heat-input-based calculations. Combustion turbines firing non-uniform fuels that contain CO_2 prior to combustion (*e.g.,* blast furnace gas or landfill gas) may sample the fuel stream to determine the quantity of CO_2 present in the fuel prior to combustion and exclude this portion of the CO_2 mass emissions from compliance determinations.

(1) Each compliance period shall include only ''valid operating hours'' in the compliance period, *i.e.,* operating hours for which:

(i) ''Valid data'' (as defined in § 60.5580) are obtained for all of the parameters used to determine the hourly CO_2 mass emissions (kg) and, if a heat input-based standard applies, all the parameters used to determine total heat input for the hour are also obtained; and

(ii) The corresponding hourly gross or net energy output value is also valid data (*Note:* For hours with no useful output, zero is considered to be a valid value).

(2) You must exclude operating hours in which:

(i) The substitute data provisions of part 75 of this chapter are applied for any of the parameters used to determine the hourly CO_2 mass emissions or, if a heat input-based standard applies, for any parameters used to determine the hourly heat input; or

(ii) An exceedance of the full-scale range of a continuous emission monitoring system occurs for any of the parameters used to determine the hourly CO_2 mass emissions or, if applicable, to determine the hourly heat input; or

(iii) The total gross or net energy output ($P_{gross/net}$) or, if applicable, the total heat input is unavailable.

(3) For each compliance period, at least 95 percent of the operating hours in the compliance period must be valid operating hours, as defined in paragraph (a)(1) of this section.

(4) You must calculate the total CO_2 mass emissions by summing the valid hourly CO_2 mass emissions values from § 60.5535 for all of the valid operating hours in the compliance period.

(5) *Sources subject to output based standards.* For each valid operating hour of the compliance period that was used in paragraph (a)(4) of this section to calculate the total CO_2 mass emissions, you must determine $P_{gross/net}$ (the corresponding hourly gross or net energy output in MWh) according to the

procedures in paragraphs (a)(3)(i) and (ii) of this section, as appropriate for the type of affected EGU(s). For an operating hour in which a valid CO_2 mass emissions value is determined according to paragraph (a)(1)(i) of this section, if there is no gross or net electrical output, but there is mechanical or useful thermal output, you must still determine the gross or net energy output for that hour. In addition, for an operating hour in which a valid CO_2 mass emissions value is determined according to paragraph (a)(1)(i) of this section, but there is no (*i.e.,* zero) gross electrical, mechanical, or useful thermal output, you must use that hour in the compliance determination. For hours or partial hours where the gross electric output is equal to or less than the auxiliary loads, net electric output shall be counted as zero for this calculation.

(i) Calculate $P_{gross/net}$ for your affected EGU using the following equation. All terms in the equation must be expressed in units of megawatt-hours (MWh). To convert each hourly gross or net energy output (consistent with § 60.5520) value reported under part 75 of this chapter to MWh, multiply by the corresponding EGU or stack operating time.

$$P_{gross/net} = \frac{(Pe)_{ST} + (Pe)_{CT} + (Pe)_{IE} - (Pe)_{FW} - (Pe)_{A}}{\text{TDF}} + [(Pt)_{PS} + (Pt)_{HR} + (Pt)_{IE}] \quad \text{(Eq. 2)}$$

Where:

$P_{gross/net}$ = In accordance with § 60.5520, gross or net energy output of your affected EGU for each valid operating hour (as defined in § 60.5540(a)(1)) in MWh.
$(Pe)_{ST}$ = Electric energy output plus mechanical energy output (if any) of steam turbines in MWh.
$(Pe)_{CT}$ = Electric energy output plus mechanical energy output (if any) of stationary combustion turbine(s) in MWh.
$(Pe)_{IE}$ = Electric energy output plus mechanical energy output (if any) of your affected EGU's integrated equipment that provides electricity or mechanical energy to the affected EGU or auxiliary equipment in MWh.
$(Pe)_{FW}$ = Electric energy used to power boiler feedwater pumps at steam generating units in MWh. Not applicable to stationary combustion turbines, IGCC EGUs, or EGUs complying with a net energy output based standard.
$(Pe)_A$ = Electric energy used for any auxiliary loads in MWh. Not applicable for determining P_{gross}.
$(Pt)_{PS}$ = Useful thermal output of steam (measured relative to SATP conditions, as applicable) that is used for applications that do not generate additional electricity, produce mechanical energy output, or enhance the performance of the affected EGU. This is calculated using the equation specified in paragraph (a)(5)(ii) of this section in MWh.
$(Pt)_{HR}$ = Non steam useful thermal output (measured relative to SATP conditions, as applicable) from heat recovery that is used for applications other than steam generation or performance enhancement of the affected EGU in MWh.
$(Pt)_{IE}$ = Useful thermal output (relative to SATP conditions, as applicable) from any integrated equipment is used for applications that do not generate additional steam, electricity, produce mechanical energy output, or enhance the performance of the affected EGU in MWh.
TDF = Electric Transmission and Distribution Factor of 0.95 for a combined heat and power affected EGU where at least on an annual basis 20.0 percent of the total gross or net energy output consists of electric or direct mechanical output and 20.0 percent of the total gross or net energy output consists of useful thermal output on a 12-operating-month rolling average basis, or 1.0 for all other affected EGUs.

(ii) If applicable to your affected EGU (for example, for combined heat and power), you must calculate $(Pt)_{PS}$ using the following equation:

$$(Pt)_{PS} = \frac{Q_m \times H}{CF} \quad \text{(Eq. 3)}$$

Where:

Q_m = Measured steam flow in kilograms (kg) (or pounds (lb)) for the operating hour.
H = Enthalpy of the steam at measured temperature and pressure (relative to SATP conditions or the energy in the condensate return line, as applicable) in Joules per kilogram (J/kg) (or Btu/lb).
CF = Conversion factor of 3.6×10^9 J/MWh or 3.413×10^6 Btu/MWh.

(6) *Calculation of annual basis for standard.* Sources complying with energy output-based standards must calculate the basis (*i.e.,* denominator) of their actual annual emission rate in accordance with paragraph (a)(6)(i) of this section. Sources complying with heat input based standards must calculate the basis of their actual annual emission rate in accordance with paragraph (a)(6)(ii) of this section.

(i) In accordance with § 60.5520 if you are subject to an output-based standard, you must calculate the total gross or net energy output for the affected EGU's compliance period by summing the hourly gross or net energy output values for the affected EGU that you determined under paragraph (a)(5) of this section for all of the valid operating hours in the applicable compliance period.

(ii) If you are subject to a heat input-based standard, you must calculate the total heat input for each fuel fired during the compliance period. The calculation of total heat input for each individual fuel must include all valid operating hours and must also be consistent with any fuel-specific procedures specified within your selected monitoring option under § 60.5535(d)(2).

(7) If you are subject to an output-based standard, you must calculate the CO_2 mass emissions rate for the affected EGU(s) (kg/MWh) by dividing the total CO_2 mass emissions value calculated according to the procedures in paragraph (a)(4) of this section by the total gross or net energy output value calculated according to the procedures in paragraph (a)(6)(i) of this section. Round off the result to two significant figures if the calculated value is less than 1,000; round the result to three significant figures if the calculated value is greater than 1,000. If you are subject to a heat input-based standard, you must calculate the CO_2 mass emissions rate for the affected EGU(s) (lb/MMBtu) by dividing the total CO_2 mass emissions value calculated according to the procedures in paragraph (a)(4) of this section by the total heat input calculated according to the procedures in paragraph (a)(6)(ii) of this section. Round off the result to two significant figures.

(b) In accordance with § 60.5520, to demonstrate compliance with the applicable CO_2 emission standard, for the initial and each subsequent 12-operating-month compliance period, the CO_2 mass emissions rate for your affected EGU must be determined according to the procedures specified in paragraph (a)(1) through (7) of this section and must be less than or equal to the applicable CO_2 emissions standard in Table 1 or 2 of this part, or the emissions standard calculated in accordance with § 60.5525(a)(2).

Notification, Reports, and Records

§ 60.5550 What notifications must I submit and when?

(a) You must prepare and submit the notifications specified in §§ 60.7(a)(1) and (3) and 60.19, as applicable to your affected EGU(s) (see Table 3 of this subpart).

(b) You must prepare and submit notifications specified in § 75.61 of this chapter, as applicable, to your affected EGUs.

§ 60.5555 What reports must I submit and when?

(a) You must prepare and submit reports according to paragraphs (a) through (d) of this section, as applicable.

(1) For affected EGUs that are required by § 60.5525 to conduct initial and on-going compliance determinations on a 12-operating-month rolling average basis, you must submit electronic quarterly reports as follows. After you have accumulated the first 12-operating months for the affected EGU, you must submit a report for the calendar quarter that includes the twelfth operating month no later than 30 days after the end of that quarter. Thereafter, you must submit a report for each subsequent calendar quarter, no later than 30 days after the end of the quarter.

(2) In each quarterly report you must include the following information, as applicable:

(i) Each rolling average CO_2 mass emissions rate for which the last (twelfth) operating month in a 12-operating-month compliance period falls within the calendar quarter. You must calculate each average CO_2 mass emissions rate for the compliance period according to the procedures in § 60.5540. You must report the dates (month and year) of the first and twelfth operating months in each compliance period for which you performed a CO_2 mass emissions rate calculation. If there are no compliance periods that end in the quarter, you must include a statement to that effect;

(ii) If one or more compliance periods end in the quarter, you must identify each operating month in the calendar quarter where your EGU violated the applicable CO_2 emission standard;

(iii) If one or more compliance periods end in the quarter and there are no violations for the affected EGU, you must include a statement indicating this in the report;

(iv) The percentage of valid operating hours in each 12-operating-month compliance period described in paragraph (a)(1)(i) of this section (*i.e.,* the total number of valid operating hours (as defined in § 60.5540(a)(1)) in that period divided by the total number of operating hours in that period, multiplied by 100 percent);

(v) Consistent with § 60.5520, the CO_2 emissions standard (as identified in Table 1 or 2 of this part) with which your affected EGU must comply; and

(vi) Consistent with § 60.5520, an indication whether or not the hourly gross or net energy output ($P_{gross/net}$) values used in the compliance determinations are based solely upon gross electrical load.

(3) In the final quarterly report of each calendar year, you must include the following:

(i) Consistent with § 60.5520, gross energy output or net energy output sold to an electric grid, as applicable to the units of your emission standard, over the four quarters of the calendar year; and

(ii) The potential electric output of the EGU.

(b) You must submit all electronic reports required under paragraph (a) of this section using the Emissions Collection and Monitoring Plan System (ECMPS) Client Tool provided by the Clean Air Markets Division in the Office of Atmospheric Programs of EPA.

(c)(1) For affected EGUs under this subpart that are also subject to the Acid Rain Program, you must meet all applicable reporting requirements and submit reports as required under subpart G of part 75 of this chapter.

(2) For affected EGUs under this subpart that are not in the Acid Rain Program, you must also meet the reporting requirements and submit reports as required under subpart G of part 75 of this chapter, to the extent that those requirements and reports provide applicable data for the compliance demonstrations required under this subpart.

(3)(i) For all newly-constructed affected EGUs under this subpart that are also subject to the Acid Rain Program, you must begin submitting the quarterly electronic emissions reports described in paragraph (c)(1) of this section in accordance with § 75.64(a) of this chapter, *i.e.,* beginning with data recorded on and after the earlier of:

(A) The date of provisional certification, as defined in § 75.20(a)(3) of this chapter; or

(B) 180 days after the date on which the EGU commences commercial operation (as defined in § 72.2 of this chapter).

(ii) For newly-constructed affected EGUs under this subpart that are not subject to the Acid Rain Program, you must begin submitting the quarterly electronic reports described in paragraph (c)(2) of this section, beginning with data recorded on and after:

(A) The date on which reporting is required to begin under § 75.64(a) of this chapter, if that date occurs on or after October 23, 2015; or

(B) October 23, 2015, if the date on which reporting would ordinarily be required to begin under § 75.64(a) of this chapter has passed prior to October 23, 2015.

(iii) For reconstructed or modified units, reporting of emissions data shall begin at the date on which the EGU becomes an affected unit under this subpart, provided that the ECMPS Client Tool is able to receive and process net energy output data on that date. Otherwise, emissions data reporting shall be on a gross energy output basis until the date that the Client Tool is first able to receive and process net energy output data.

(4) If any required monitoring system has not been provisionally certified by the applicable date on which emissions data reporting is required to begin under paragraph (c)(3) of this section, the maximum (or in some cases, minimum) potential value for the parameter measured by the monitoring system shall be reported until the required certification testing is successfully completed, in accordance with § 75.4(j) of this chapter, § 75.37(b) of this chapter, or section 2.4 of appendix D to part 75 of this chapter (as applicable). Operating hours in which CO_2 mass emission rates are calculated using maximum potential values are not ''valid operating hours'' (as defined in § 60.5540(a)(1)), and shall not be used in the compliance determinations under § 60.5540.

(d) For affected EGUs subject to the Acid Rain Program, the reports required under paragraphs (a) and (c)(1) of this section shall be submitted by:

(1) The person appointed as the Designated Representative (DR) under § 72.20 of this chapter; or

(2) The person appointed as the Alternate Designated Representative (ADR) under § 72.22 of this chapter; or

(3) A person (or persons) authorized by the DR or ADR under § 72.26 of this chapter to make the required submissions.

(e) For affected EGUs that are not subject to the Acid Rain Program, the owner or operator shall appoint a DR and (optionally) an ADR to submit the reports required under paragraphs (a) and (c)(2) of this section. The DR and ADR must register with the Clean Air Markets Division (CAMD) Business System. The DR may delegate the authority to make the required submissions to one or more persons.

(f) If your affected EGU captures CO_2 to meet the applicable emission limit, you must report in accordance with the requirements of 40 CFR part 98, subpart PP and either:

(1) Report in accordance with the requirements of 40 CFR part 98, subpart RR, if injection occurs on-site, or

(2) Transfer the captured CO_2 to an EGU or facility that reports in accordance with the requirements of 40 CFR part 98, subpart RR, if injection occurs off-site.

(3) Transfer the captured CO_2 to a facility that has received an innovative technology waiver from EPA pursuant to paragraph (g) of this section.

(g) Any person may request the Administrator to issue a waiver of the requirement that captured CO_2 from an affected EGU be transferred to a facility reporting under 40 CFR part 98, subpart RR. To receive a waiver, the applicant must demonstrate to the Administrator that its technology will store captured CO_2 as effectively as geologic sequestration, and that the proposed technology will not cause or contribute to an unreasonable risk to public health, welfare, or safety. In making this determination, the Administrator shall consider (among other factors) operating history of the technology, whether the technology will increase emissions or other releases of any pollutant other than CO_2, and permanence of the CO_2 storage. The Administrator may test the system itself, or require the applicant to perform any tests considered by the Administrator to be necessary to show the technology's effectiveness, safety, and ability to store captured CO_2 without release. The Administrator may grant conditional approval of a technology, with the approval conditioned on monitoring and reporting of operations. The Administrator may also withdraw approval of the waiver on evidence of releases of CO_2 or other pollutants. The Administrator will provide notice to the public of any application under this provision and provide public notice of any proposed action on a petition before the Administrator takes final action.

§ 60.5560 What records must I maintain?

(a) You must maintain records of the information you used to demonstrate compliance with this subpart as specified in § 60.7(b) and (f).

(b)(1) For affected EGUs subject to the Acid Rain Program, you must follow the applicable recordkeeping requirements and maintain records as required under subpart F of part 75 of this chapter.

(2) For affected EGUs that are not subject to the Acid Rain Program, you must also follow the recordkeeping requirements and maintain records as required under subpart F of part 75 of this chapter, to the extent that those records provide applicable data for the compliance determinations required under this subpart. Regardless of the prior sentence, at a minimum, the following records must be kept, as applicable to the types of continuous monitoring systems used to demonstrate compliance under this subpart:

(i) Monitoring plan records under § 75.53(g) and (h) of this chapter;

(ii) Operating parameter records under § 75.57(b)(1) through (4) of this chapter;

(iii) The records under § 75.57(c)(2) of this chapter, for stack gas volumetric flow rate;

(iv) The records under § 75.57(c)(3) of this chapter for continuous moisture monitoring systems;

(v) The records under § 75.57(e)(1) of this chapter, except for paragraph (e)(1)(x), for CO_2 concentration monitoring systems or O_2 monitors used to calculate CO_2 concentration;

(vi) The records under § 75.58(c)(1) of this chapter, specifically paragraphs (c)(1)(i), (ii), and (viii) through (xiv), for oil flow meters;

(vii) The records under § 75.58(c)(4) of this chapter, specifically paragraphs (c)(4)(i), (ii), (iv), (v), and (vii) through (xi), for gas flow meters;

(viii) The quality-assurance records under § 75.59(a) of this chapter, specifically paragraphs (a)(1) through (12) and (15), for CEMS;

(ix) The quality-assurance records under § 75.59(a) of this chapter, specifically paragraphs (b)(1) through (4), for fuel flow meters; and

(x) Records of data acquisition and handling system (DAHS) verification under § 75.59(e) of this chapter.

(c) You must keep records of the calculations you performed to determine the hourly and total CO_2 mass emissions (tons) for:

(1) Each operating month (for all affected EGUs); and

(2) Each compliance period, including, each 12-operating-month compliance period.

(d) Consistent with § 60.5520, you must keep records of the applicable data recorded and calculations performed that you used to determine your affected EGU's gross or net energy output for each operating month.

(e) You must keep records of the calculations you performed to determine the percentage of valid CO_2 mass emission rates in each compliance period.

(f) You must keep records of the calculations you performed to assess compliance with each applicable CO_2 mass emissions standard in Table 1 or 2 of this subpart.

(g) You must keep records of the calculations you performed to determine any site-specific carbon-based F-factors you used in the emissions calculations (if applicable).

§ 60.5565 In what form and how long must I keep my records?

(a) Your records must be in a form suitable and readily available for expeditious review.

(b) You must maintain each record for 3 years after the date of conclusion of each compliance period.

(c) You must maintain each record on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to § 60.7. Records that are accessible from a central location by a computer or other means that instantly provide access at the site meet this requirement. You may maintain the records off site for the remaining year(s) as required by this subpart.

Other Requirements and Information

§ 60.5570 What parts of the general provisions apply to my affected EGU?

Notwithstanding any other provision of this chapter, certain parts of the general provisions in §§ 60.1 through 60.19, listed in Table 3 to this subpart, do not apply to your affected EGU.

§ 60.5575 Who implements and enforces this subpart?

(a) This subpart can be implemented and enforced by the EPA, or a delegated authority such as your state, local, or tribal agency. If the Administrator has delegated authority to your state, local, or tribal agency, then that agency (as well as the EPA) has the authority to implement and enforce this subpart. You should contact your EPA Regional Office to find out if this subpart is delegated to your state, local, or tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a state, local, or tribal agency, the Administrator retains the authorities listed in paragraphs (b)(1) through (5) of this section and does not transfer them to the state, local, or tribal agency. In addition, the EPA retains oversight of this subpart and can take enforcement actions, as appropriate.

(1) Approval of alternatives to the emission standards.

(2) Approval of major alternatives to test methods.

(3) Approval of major alternatives to monitoring.

(4) Approval of major alternatives to recordkeeping and reporting.

(5) Performance test and data reduction waivers under § 60.8(b).

§ 60.5580 What definitions apply to this subpart?

As used in this subpart, all terms not defined herein will have the meaning given them in the Clean Air Act and in subpart A (general provisions of this part).

Annual capacity factor means the ratio between the actual heat input to an EGU during a calendar year and the potential heat input to the EGU had it been operated for 8,760 hours during a calendar year at the base load rating.

Base load rating means the maximum amount of heat input (fuel) that an EGU can combust on a steady state basis, as determined by the physical design and characteristics of the EGU at ISO conditions. For a stationary combustion turbine, *base load rating* includes the heat input from duct burners.

Coal means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by ASTM International in ASTM D388–99 (Reapproved 2004) ε^1 (incorporated by reference, see § 60.17), coal refuse, and petroleum coke. Synthetic fuels derived from coal for the purpose of creating useful heat, including, but not limited to, solvent-refined coal, gasified coal (not meeting the definition of natural gas), coal-oil mixtures, and coal-water mixtures are included in this definition for the purposes of this subpart.

Combined cycle unit means an electric generating unit that uses a stationary combustion turbine from which the heat from the turbine exhaust gases is recovered by a heat recovery steam generating unit (HRSG) to generate additional electricity.

Combined heat and power unit or *CHP unit, (*also known as ''cogeneration'') means an electric generating unit that that use a steam generating unit or stationary combustion turbine to simultaneously produce both electric (or mechanical) and useful thermal output from the same primary energy source.

Design efficiency means the rated overall net efficiency (*e.g.,* electric plus useful thermal output) on a lower heating value basis at the base load rating, at ISO conditions, and at the maximum useful thermal output (*e.g.,* CHP unit with condensing steam turbines would determine the design efficiency at the maximum level of extraction and/or bypass). Design efficiency shall be determined using one of the following methods: ASME PTC 22 Gas Turbines (incorporated by reference, see § 60.17), ASME PTC 46 Overall Plant Performance (incorporated by reference, see § 60.17) or ISO 2314 Gas turbines—acceptance tests (incorporated by reference, see § 60.17).

Distillate oil means fuel oils that comply with the specifications for fuel oil numbers 1 and 2, as defined by ASTM International in ASTM D396–98 (incorporated by reference, see § 60.17); diesel fuel oil numbers 1 and 2, as defined by ASTM International in ASTM D975–08a (incorporated by reference, see § 60.17); kerosene, as defined by ASTM International in ASTM D3699 (incorporated by reference, see § 60.17); biodiesel as defined by ASTM International in ASTM D6751 (incorporated by reference, see § 60.17); or biodiesel blends as defined by ASTM International in ASTM D7467 (incorporated by reference, see § 60.17).

Electric Generating units or EGU means any steam generating unit, IGCC unit, or stationary combustion turbine that is subject to this rule (*i.e.,* meets the applicability criteria)

Fossil fuel means natural gas, petroleum, coal, and any form of solid, liquid, or gaseous fuel derived from such material for the purpose of creating useful heat.

Gaseous fuel means any fuel that is present as a gas at ISO conditions and includes, but is not limited to, natural gas, refinery fuel gas, process gas, coke-oven gas, synthetic gas, and gasified coal.

Gross energy output means:

(1) For stationary combustion turbines and IGCC, the gross electric or direct mechanical output from both the EGU (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)) plus 100 percent of the useful thermal output.

(2) For steam generating units, the gross electric or mechanical output from the affected EGU(s) (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)) minus any electricity used to power the feedwater pumps plus 100 percent of the useful thermal output;

(3) For combined heat and power facilities where at least 20.0 percent of the total gross energy output consists of electric or direct mechanical output and 20.0 percent of the total gross energy output consists of useful thermal output on a 12-operating-month rolling average basis, the gross electric or mechanical output from the affected EGU (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)) minus any electricity used to power the feedwater pumps (the electric auxiliary load of boiler feedwater pumps is not applicable to IGCC facilities), that difference divided by 0.95, plus 100 percent of the useful thermal output.

Heat recovery steam generating unit (HRSG) means an EGU in which hot exhaust gases from the combustion turbine engine are routed in order to extract heat from the gases and generate useful output. Heat recovery steam generating units can be used with or without duct burners.

Integrated gasification combined cycle facility or *IGCC* means a combined cycle facility that is designed to burn fuels containing 50 percent (by heat input) or more solid-derived fuel not meeting the definition of natural gas, plus any integrated equipment that provides electricity or useful thermal output to the affected EGU or auxiliary equipment. The Administrator may waive the 50 percent solid-derived fuel requirement during periods of the gasification system construction, startup and commissioning, shutdown, or repair. No solid fuel is directly burned in the EGU during operation.

ISO conditions means 288 Kelvin (15°C), 60 percent relative humidity and 101.3 kilopascals pressure.

Liquid fuel means any fuel that is present as a liquid at ISO conditions and includes, but is not limited to, distillate oil and residual oil.

Mechanical output means the useful mechanical energy that is not used to operate the affected EGU(s), generate electricity and/or thermal energy, or to enhance the performance of the affected EGU. Mechanical energy measured in horsepower hour should be converted into MWh by multiplying it by 745.7 then dividing by 1,000,000.

Natural gas means a fluid mixture of hydrocarbons (*e.g.,* methane, ethane, or propane), composed of at least 70 percent methane by volume or that has a gross calorific value between 35 and 41 megajoules (MJ) per dry standard cubic meter (950 and 1,100 Btu per dry standard cubic foot), that maintains a gaseous state under ISO conditions. Finally, natural gas does not include the following gaseous fuels: Landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable CO_2 content or heating value.

Net-electric sales means:

(1) The gross electric sales to the utility power distribution system minus purchased power; or

(2) For combined heat and power facilities where at least 20.0 percent of the total gross energy output consists of electric or direct mechanical output and at least 20.0 percent of the total gross energy output consists of useful thermal output on an annual basis, the gross electric sales to the utility power

distribution system minus purchased power of the thermal host facility or facilities.

(3) Electricity supplied to other facilities that produce electricity to offset auxiliary loads are included when calculating net-electric sales.

(4) Electric sales that that result from a system emergency are not included when calculating net-electric sales.

Net-electric output means the amount of gross generation the generator(s) produces (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)), as measured at the generator terminals, less the electricity used to operate the plant (*i.e.,* auxiliary loads); such uses include fuel handling equipment, pumps, fans, pollution control equipment, other electricity needs, and transformer losses as measured at the transmission side of the step up transformer (*e.g.,* the point of sale).

Net energy output means:

(1) The net electric or mechanical output from the affected EGU plus 100 percent of the useful thermal output; or

(2) For combined heat and power facilities where at least 20.0 percent of the total gross or net energy output consists of electric or direct mechanical output and at least 20.0 percent of the total gross or net energy output consists of useful thermal output on a 12-operating-month rolling average basis, the net electric or mechanical output from the affected EGU divided by 0.95, plus 100 percent of the useful thermal output.

Operating month means a calendar month during which any fuel is combusted in the affected EGU at any time.

Petroleum means crude oil or a fuel derived from crude oil, including, but not limited to, distillate and residual oil.

Potential electric output means 33 percent or the base load rating design efficiency at the maximum electric production rate (*e.g.,* CHP units with condensing steam turbines will operate at maximum electric production), whichever is greater, multiplied by the base load rating (expressed in MMBtu/h) of the EGU, multiplied by 10^6 Btu/MMBtu, divided by 3,413 Btu/KWh, divided by 1,000 kWh/MWh, and multiplied by 8,760 h/yr (*e.g.,* a 35 percent efficient affected EGU with a 100 MW (341 MMBtu/h) fossil fuel heat input capacity would have a 306,000 MWh 12-month potential electric output capacity).

Standard ambient temperature and pressure (SATP) conditions means 298.15 Kelvin (25 °C, 77 °F) and 100.0 kilopascals (14.504 psi, 0.987 atm) pressure. The enthalpy of water at SATP conditions is 50 Btu/lb.

Solid fuel means any fuel that has a definite shape and volume, has no tendency to flow or disperse under moderate stress, and is not liquid or gaseous at ISO conditions. This includes, but is not limited to, coal, biomass, and pulverized solid fuels.

Stationary combustion turbine means all equipment including, but not limited to, the turbine engine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), heat recovery system, fuel compressor, heater, and/or pump, post-combustion emission control technology, and any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any combined cycle combustion turbine, and any combined heat and power combustion turbine based system plus any integrated equipment that provides electricity or useful thermal output to the combustion turbine engine, heat recovery system or auxiliary equipment. Stationary means that the combustion turbine is not self-propelled or intended to be propelled while performing its function. It may, however, be mounted on a vehicle for portability. A stationary combustion turbine that burns any solid fuel directly is considered a steam generating unit.

Steam generating unit means any furnace, boiler, or other device used for combusting fuel and producing steam (nuclear steam generators are not included) plus any integrated equipment that provides electricity or useful thermal output to the affected EGU(s) or auxiliary equipment.

System emergency means any abnormal system condition that the Regional Transmission Organizations (RTO), Independent System Operators (ISO) or control area Administrator determines requires immediate automatic or manual action to prevent or limit loss of transmission facilities or generators that could adversely affect the reliability of the power system and therefore call for maximum generation resources to operate in the affected area, or for the specific affected EGU to operate to avert loss of load.

Useful thermal output means the thermal energy made available for use in any heating application (*e.g.,* steam delivered to an industrial process for a heating application, including thermal cooling applications) that is not used for electric generation, mechanical output at the affected EGU, to directly enhance the performance of the affected EGU (*e.g.,* economizer output is not useful thermal output, but thermal energy used to reduce fuel moisture is considered useful thermal output), or to supply energy to a pollution control device at the affected EGU. Useful thermal output for affected EGU(s) with no condensate return (or other thermal energy input to the affected EGU(s)) or where measuring the energy in the condensate (or other thermal energy input to the affected EGU(s)) would not meaningfully impact the emission rate calculation is measured against the energy in the thermal output at SATP conditions. Affected EGU(s) with meaningful energy in the condensate return (or other thermal energy input to the affected EGU) must measure the energy in the condensate and subtract that energy relative to SATP conditions from the measured thermal output.

Valid data means quality-assured data generated by continuous monitoring systems that are installed, operated, and maintained according to part 75 of this chapter. For CEMS, the initial certification requirements in § 75.20 of this chapter and appendix A to part 75 of this chapter must be met before quality-assured data are reported under this subpart; for on-going quality assurance, the daily, quarterly, and semiannual/annual test requirements in sections 2.1, 2.2, and 2.3 of appendix B to part 75 of this chapter must be met and the data validation criteria in sections 2.1.5, 2.2.3, and 2.3.2 of appendix B to part 75 of this chapter apply. For fuel flow meters, the initial certification requirements in section 2.1.5 of appendix D to part 75 of this chapter must be met before quality-assured data are reported under this subpart (except for qualifying commercial billing meters under section 2.1.4.2 of appendix D to part 75), and for on-going quality assurance, the provisions in section 2.1.6 of appendix D to part 75 apply (except for qualifying commercial billing meters).

Violation means a specified averaging period over which the CO_2 emissions rate is higher than the applicable emissions standard located in Table 1 or 2 of this subpart.

TABLE 1 OF SUBPART TTTT OF PART 60—CO_2 EMISSION STANDARDS FOR AFFECTED STEAM GENERATING UNITS AND INTEGRATED GASIFICATION COMBINED CYCLE FACILITIES THAT COMMENCED CONSTRUCTION AFTER JANUARY 8, 2014 AND RECONSTRUCTION OR MODIFICATION AFTER JUNE 18, 2014

[Note: Numerical values of 1,000 or greater have a minimum of 3 significant figures and numerical values of less than 1,000 have a minimum of 2 significant figures]

Affected EGU	CO_2 Emission standard
Newly constructed steam generating unit or integrated gasification combined cycle (IGCC).	640 kg CO_2/MWh of gross energy output (1,400 lb CO_2/MWh).
Reconstructed steam generating unit or IGCC that has base load rating of 2,100 GJ/h (2,000 MMBtu/h) or less.	910 kg of CO_2 per MWh of gross energy output (2,000 lb CO_2/MWh).
Reconstructed steam generating unit or IGCC that has a base load rating greater than 2,100 GJ/h (2,000 MMBtu/h).	820 kg of CO_2 per MWh of gross energy output (1,800 lb CO_2/MWh).
Modified steam generating unit or IGCC	A unit-specific emission limit determined by the unit's best historical annual CO_2 emission rate (from 2002 to the date of the modification); the emission limit will be no lower than: 1. 1,800 lb CO_2/MWh-gross for units with a base load rating greater than 2,000 MMBtu/h; or 2. 2,000 lb CO_2/MWh-gross for units with a base load rating of 2,000 MMBtu/h or less.

TABLE 2 OF SUBPART TTTT OF PART 60—CO_2 EMISSION STANDARDS FOR AFFECTED STATIONARY COMBUSTION TURBINES THAT COMMENCED CONSTRUCTION AFTER JANUARY 8, 2014 AND RECONSTRUCTION AFTER JUNE 18, 2014 (NET ENERGY OUTPUT-BASED STANDARDS APPLICABLE AS APPROVED BY THE ADMINISTRATOR)

[Note: Numerical values of 1,000 or greater have a minimum of 3 significant figures and numerical values of less than 1,000 have a minimum of 2 significant figures]

Affected EGU	CO_2 Emission standard
Newly constructed or reconstructed stationary combustion turbine that supplies more than its design efficiency or 50 percent, whichever is less, times its potential electric output as net-electric sales on both a 12-operating month and a 3-year rolling average basis and combusts more than 90% natural gas on a heat input basis on a 12-operating-month rolling average basis.	450 kg of CO_2 per MWh of gross energy output (1,000 lb CO_2/MWh); or 470 kilograms (kg) of CO_2 per megawatt-hour (MWh) of net energy output (1,030 lb/MWh).
Newly constructed or reconstructed stationary combustion turbine that supplies its design efficiency or 50 percent, whichever is less, times its potential electric output or less as net-electric sales on either a 12-operating month or a 3-year rolling average basis and combusts more than 90% natural gas on a heat input basis on a 12-operating-month rolling average basis.	50 kg CO_2 per gigajoule (GJ) of heat input (120 lb CO_2/MMBtu).
Newly constructed and reconstructed stationary combustion turbine that combusts 90% or less natural gas on a heat input basis on a 12-operating-month rolling average basis.	50 kg CO_2/GJ of heat input (120 lb/MMBtu) to 69 kg CO_2/GJ of heat input (160 lb/MMBtu) as determined by the procedures in § 60.5525.

TABLE 3 TO SUBPART TTTT OF PART 60—APPLICABILITY OF SUBPART A OF PART 60 (GENERAL PROVISIONS) TO SUBPART TTTT

General provisions citation	Subject of citation	Applies to subpart TTTT	Explanation
§ 60.1	Applicability	Yes.	
§ 60.2	Definitions	Yes	Additional terms defined in § 60.5580.
§ 60.3	Units and Abbreviations	Yes.	
§ 60.4	Address	Yes	Does not apply to information reported electronically through ECMPS. Duplicate submittals are not required.
§ 60.5	Determination of construction or modification	Yes.	
§ 60.6	Review of plans	Yes.	
§ 60.7	Notification and Recordkeeping	Yes	Only the requirements to submit the notifications in § 60.7(a)(1) and (3) and to keep records of malfunctions in § 60.7(b), if applicable.
§ 60.8	Performance tests	No.	
§ 60.9	Availability of Information	Yes.	
§ 60.10	State authority	Yes.	
§ 60.11	Compliance with standards and maintenance requirements.	No.	
§ 60.12	Circumvention	Yes.	
§ 60.13	Monitoring requirements	No	All monitoring is done according to part 75.

TABLE 3 TO SUBPART TTTT OF PART 60—APPLICABILITY OF SUBPART A OF PART 60 (GENERAL PROVISIONS) TO SUBPART TTTT—Continued

General provisions citation	Subject of citation	Applies to subpart TTTT	Explanation
§ 60.14	Modification	Yes (steam generating units and IGCC facilities). No (stationary combustion turbines.	
§ 60.15	Reconstruction	Yes.	
§ 60.16	Priority list	No.	
§ 60.17	Incorporations by reference	Yes.	
§ 60.18	General control device requirements	No.	
§ 60.19	General notification and reporting requirements	Yes	Does not apply to notifications under § 75.61 or to information reported through ECMPS.

PART 70—STATE OPERATING PERMIT PROGRAMS

■ 4. The authority citation for part 70 continues to read as follows:

Authority: 42 U.S.C. 7401, *et seq.*

■ 5. In § 70.2, the definition of ''Regulated pollutant (for presumptive fee calculation)'' is amended by:
■ a. Revising the introductory text;
■ b. Removing ''or'' from the end of paragraph (2);
■ c. Removing the period at the end of paragraph (3) and adding ''; or'' in its place; and
■ d. Adding paragraph (4).

The revision and additions read as follows:

§ 70.2 Definitions.

* * * * *

Regulated pollutant (for presumptive fee calculation), which is used only for purposes of § 70.9(b)(2), means any regulated air pollutant except the following:

* * * * *

(4) Greenhouse gases.

* * * * *

■ 6. Section 70.9 is amended by revising paragraph (b)(2)(i), and adding paragraph (b)(2)(v) to read as follows:

§ 70.9 Fee determination and certification.

* * * * *

(b) * * *

(2)(i) The Administrator will presume that the fee schedule meets the requirements of paragraph (b)(1) of this section if it would result in the collection and retention of an amount not less than $25 per year [as adjusted pursuant to the criteria set forth in paragraph (b)(2)(iv) of this section] times the total tons of the actual emissions of each regulated pollutant (for presumptive fee calculation) emitted from part 70 sources and any GHG cost adjustment required under paragraph (b)(2)(v) of this section.

* * * * *

(v) *GHG cost adjustment.* The amount calculated in paragraph (b)(2)(i) of this section shall be increased by the GHG cost adjustment determined as follows: For each activity identified in the following table, multiply the number of activities performed by the permitting authority by the burden hours per activity, and then calculate a total number of burden hours for all activities. Next, multiply the burden hours by the average cost of staff time, including wages, employee benefits and overhead.

Activity	Burden hours per activity
GHG completeness determination (for initial permit or updated application)	43
GHG evaluation for a permit modification or related permit action	7
GHG evaluation at permit renewal	10

* * * * *

PART 71—FEDERAL OPERATING PERMIT PROGRAMS

■ 7. The authority citation for part 71 continues to read as follows:

Authority: 42 U.S.C. 7401, *et seq.*

■ 8. In § 71.2, the definition of ''Regulated pollutant (for fee calculation)'' is amended by:
■ a. Removing ''or'' from the end of paragraph (2);
■ b. Removing the period at the end of paragraph (3) and adding ''; or'' in its place; and
■ b. Adding paragraph (4).

The revisions and additions read as follows:

§ 71.2 Definitions.

* * * * *

Regulated pollutant (for fee calculation), which is used only for purposes of § 71.9(c), means any ''*regulated air pollutant''* except the following:

* * * * *

(4) Greenhouse gases.

* * * * *

■ 9. Section 71.9 is amended by:
■ a. Revising paragraphs (c)(1), (c)(2)(i), (c)(3), and (c)(4); and
■ b. Adding paragraph (c)(8).

The revisions and addition read as follows:

§ 71.9 Permit fees.

* * * * *

(c) * * *

(1) For part 71 programs that are administered by EPA, each part 71 source shall pay an annual fee which is the sum of:

(i) $32 per ton (as adjusted pursuant to the criteria set forth in paragraph (n)(1) of this section) times the total tons of the actual emissions of each regulated pollutant (for fee calculation) emitted from the source, including fugitive emissions; and

(ii) Any GHG fee adjustment required under paragraph (c)(8) of this section.

(2) * * *

(i) Where the EPA has not suspended its part 71 fee collection pursuant to paragraph (c)(2)(ii) of this section, the annual fee for each part 71 source shall be the sum of:

(A) $24 per ton (as adjusted pursuant to the criteria set forth in paragraph (n)(1) of this section) times the total tons of the actual emissions of each regulated pollutant (for fee calculation) emitted from the source, including fugitive emissions; and

(B) Any GHG fee adjustment required under paragraph (c)(8) of this section.

* * * * *

(3) For part 71 programs that are administered by EPA with contractor assistance, the per ton fee shall vary depending on the extent of contractor involvement and the cost to EPA of contractor assistance. The EPA shall establish a per ton fee that is based on the contractor costs for the specific part 71 program that is being administered, using the following formula:

Cost per ton = $(E \times 32) + [(1 - E) \times \$C]$

Where E represents EPA's proportion of total effort (expressed as a percentage of total effort) needed to administer the part 71 program, $1 - E$ represents the contractor's effort, and C represents the contractor assistance cost on a per ton basis. C shall be computed by using the following formula:

$C = [B + T + N]$ divided by 12,300,000

Where B represents the base cost (contractor costs), where T represents travel costs, and where N represents nonpersonnel data management and tracking costs. In addition, each part 71 source shall pay a GHG fee adjustment for each activity as required under paragraph (c)(8) of this section.

(4) For programs that are delegated in part, the fee shall be computed using the following formula:

Cost per ton = $(E \times 32) + (D \times 24) + [(1 - E - D) \times \$C]$

Where E and D represent, respectively, the EPA and delegate agency proportions of total effort (expressed as a percentage of total effort) needed to administer the part 71 program, $1 - E - D$ represents the contractor's effort, and C represents the contractor assistance cost on a per ton basis. C shall be computed using the formula for contractor assistance cost found in paragraph (c)(3) of this section and shall be zero if contractor assistance is not utilized. In addition, each part 71 source shall pay a GHG fee adjustment for each activity as required under paragraph (c)(8) of this section.

* * * * *

(8) *GHG fee adjustment.* The annual fee shall be increased by a GHG fee adjustment for any source that has initiated an activity listed in the following table since the fee was last paid. The GHG fee adjustment shall be equal to the set fee provided in the table for each activity that has been initiated since the fee was last paid:

Activity	Set fee
GHG completeness determination (for initial permit or updated application)	$2,236
GHG evaluation for a permit modification or related permit action	364
GHG evaluation at permit renewal	520

* * * * *

PART 98—MANDATORY GREENHOUSE GAS REPORTING

■ 10. The authority citation for part 98 is revised to read as follows:

Authority: 42 U.S.C. 7401–7671q.

■ 11. Section 98.426 is amended by adding paragraph (h) to read as follows:

§ 98.426 Data reporting requirements.

* * * * *

(h) If you capture a CO_2 stream from an electricity generating unit that is subject to subpart D of this part and transfer CO_2 to any facilities that are subject to subpart RR of this part, you must:

(1) Report the facility identification number associated with the annual GHG report for the subpart D facility;

(2) Report each facility identification number associated with the annual GHG reports for each subpart RR facility to which CO_2 is transferred; and

(3) Report the annual quantity of CO_2 in metric tons that is transferred to each subpart RR facility.

■ 12. Section 98.427 is amended by adding paragraph (d) to read as follows:

§ 98.427 Records that must be retained.

* * * * *

(d) Facilities subject to § 98.426(h) must retain records of CO_2 in metric tons that is transferred to each subpart RR facility.

[FR Doc. 2015–22837 Filed 10–22–15; 8:45 am]

BILLING CODE 6560–50–P

ORAL ARGUMENT NOT YET SCHEDULED

No. 15-1381 (and consolidated cases)

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

STATE OF NORTH DAKOTA, *et al.*,

Petitioners,

v.

U.S. ENVIRONMENTAL PROTECTION AGENCY, *et al.*,

Respondents.

On Petition for Review of Final Agency Action
of the U.S. Environmental Protection Agency
80 Fed. Reg. 64,510 (Oct. 23, 2015)

STATE OF NORTH DAKOTA'S ADDENDUM
PURSUANT TO CIRCUIT RULE 28(a)(7)

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DATED: October 13, 2016

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CERTIFICATE OF SERVICE

I hereby certify that, on this 13th day of October 2016, a copy of the State of North Dakota's Addendum Pursuant to Circuit Rule 28(a)(7) was served electronically through the Court's CM/ECF system on all ECF-registered counsel.

/s/ Paul M. Seby

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

STATE OF NORTH DAKOTA Petitioner, v. UNITED STATES ENVIRONMENTAL PROTECTION AGENCY, Respondent.	**DECLARATION OF RANDEL D. CHRISTMANN** **Case No. 15-1381**

I, Randel D. Christmann, state and declare as follows:

1. My name is Randel D. Christmann. I am over 21 years of age and am fully competent and duly authorized to make this Declaration. The facts contained in this Declaration are based on my personal knowledge and are true and correct.

2. I am an elected Commissioner of the North Dakota Public Service Commission ("PSC"). I have held my office as Commissioner at the PSC since January 1, 2013.

3. The PSC is a state agency established by the North Dakota Constitution. N.D. Const. Art. 5, § 2. The statutory authority of the PSC is set forth in the North Dakota Century Code, Ch. 49-01 *et seq.*, Titles 60 and 64, and Chs. 24-01, 24-09, 38-14.1, 38-14.2, 38-18, and 51-05.1. The PSC has general jurisdiction over "[e]lectric utilities engaged in the generation and distribution of light, heat, or power." N.D.

Cent. Code § 49-02-01. The PSC supervises public utilities with the power to "originate, establish, modify, adjust, promulgate, and enforce tariffs, rates, joint rates, and charges of all public utilities." *Id.* § 49-02-03. The PSC shall determine the value of property of every public utility "for the purpose of ascertaining just and reasonable rates and charges of public utilities," *id.* § 49-06-01, including "new facilities that use lignite mined in the state to generate electricity." *Id.* § 49-06-02. The PSC "may approve, reject, or modify a tariff filed under section 49-05-06 which provides for an adjustment of rates to recover jurisdictional capital and operating costs incurred by a public utility for new or modified electric transmission facilities." *Id.* § 49-05-04.3.

4. The PSC has a statutory duty to ensure that North Dakotans receive a reliable supply of electricity at just and reasonable rates. Additionally, the PSC is responsible for determining whether to authorize new generation and transmission infrastructure in North Dakota that is needed by jurisdictional utilities to provide reliable electric service to customers and is otherwise consistent with State law. *Id.* § 49-03.

5. In my position, I am familiar with the final rule promulgated by the U.S. Environmental Protection Agency ("EPA") entitled "Standards of Performance: Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units," 80 Fed. Reg. 64,510 (Oct. 23, 2015) ("Final Rule").

6. This Declaration has been reviewed by the other two members of the North Dakota Public Service Commission, Commission Chairman Julie Fedorchak and Commissioner Brian Kalk. The Commission held a public meeting on October 12, 2016, and voted to unanimously endorse the content and filing of this Declaration as the official position of the North Dakota Public Service Commission.

7. The Final Rule is part of a complex effort aimed at forcing North Dakota and its utilities to engage in a significant shift in North Dakota's electrical generating capacity away from carbon-intensive electric generating units, such as those fueled by lignite coal, to less carbon-intensive sources. Such an extreme mandate adversely impacts North Dakota's citizens, businesses, and government agencies like the PSC.

8. The Final Rule sets a standard of performance that is unachievable for new coal-fired power plants. As a result, the Final Rule is a *de facto* ban on any new coal-fired power plants in the State of North Dakota.

9. In promulgating the Final Rule, EPA is regulating out of existence lignite-fired power plants and establishing itself as the dictator of energy policy for North Dakota by executive decree. This infringes on the province of Congress in the establishment of national energy policy, and it preempts the PSC in performing its statutory duties to determine how best North Dakota's significant electricity demand can be met.

10. The proposed rule is inconsistent with the well-established interpretation and application of Section 111 of the CAA, which has been to implement Congressional policy to set achievable environmental standards, not to make EPA the energy policymaker for the country. Conventional generation, such as that from North Dakota lignite, is very important for maintaining a reliable, stable, and low-cost electric grid. Absent the retention of conventional coal-fired EGUs, electricity costs will dramatically increase, which will particularly hurt those who can least afford to pay.

11. The regulatory burden being imposed by EPA in the Final Rule will limit the ability of many consumers in North Dakota to use and enjoy electricity and modern electrical conveniences. The Final Rule also threatens North Dakota's ability to continue to use lignite and other coals as a low-cost electricity-generation option, and as a means to enable development of the Bakken oil reserves that are critical to North Dakota's continued economic development.

12. North Dakota has an abundant supply of lignite coal that can be used to meet the future projected electricity demands in an economical and responsible fashion. New efficient lignite-fueled baseload electric generation facilities should not be prohibited by the Final Rule from merely being an option available to meet this substantial demand.

Executed on October 12, 2016.

Randel Christmann

Randel D. Christmann

The foregoing Declaration of Randel D. Christmann was subscribed and sworn before me by Randel D. Christmann on October 12, 2016.

Witness my hand and official seal.

Charlene A Magstadt

Notary Public

My commission expires: ___________________

CHARLENE A MAGSTADT
Notary Public
State of North Dakota
My Commission Expires Feb 12, 2022

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

STATE OF NORTH DAKOTA

Petitioner,

v.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY,

Respondent.

DECLARATION OF KARLENE FINE

Case No. 15-1381

I, Karlene Fine, state and declare as follows:

1. My name is Karlene Fine. I am over 21 years of age and am fully competent to make this Declaration. I make this Declaration in accordance with my position and responsibilities, and the facts contained in this Declaration are based on my personal knowledge and are true and correct.

2. I am employed as the Secretary of the North Dakota Industrial Commission ("Commission"). I was appointed to this position in April 1974, and I have continuously served as the Secretary of the Commission since 1974.

3. The Legislature created the Commission in 1919 to conduct and manage, on behalf of the State, certain utilities, industries, enterprises and business projects established by state law. The Commission is made up of three statewide elected officials—the Governor, Attorney General, and Agriculture Commissioner.

4. The Commission's Lignite Research, Development and Marketing Program ("Lignite Program") is a multi-million dollar state-industry partnership that concentrates on near-term, practical research and development projects for the future that provide the opportunity to preserve and enhance development of our State's abundant lignite resources. The Lignite Program plays a significant role in fulfilling North Dakota's statutory obligation to "protect, preserve, and enhance development of North Dakota's abundant lignite resources for the benefit of its citizens." *See* N.D. Cent. Code § 54-17.5-01.

5. In my capacity as Industrial Commission Secretary I serve as the Contract Officer of all the projects that are funded under the Lignite Program and authorize all the payments. All reports submitted to the Commission under the Lignite Program are reviewed by technical experts and me prior to any payments being made.

6. The Program is funded by approximately 10 cents per ton from the North Dakota coal severance tax. With annual production at approximately 30 million tons per year, that means about $3 million is available each year for the Lignite Program's Research, Development and Marketing Program.

7. As discussed on the Commission's Lignite Program website, the goals of the Lignite Program include:

- Promoting economic, efficient, and clean uses of lignite and products derived from lignite in order to maintain and enhance development of North Dakota lignite and its products;

- Preserving and creating new jobs involved in the production and utilization of North Dakota lignite;

- Ensuring economic stability, growth, and opportunity in the lignite industry;

- Maintaining a stable and competitive tax base for our state's lignite industry for the general welfare of North Dakota; and

- Conducting development in an environmentally-sound manner that protects our state's air, water, and soil.

8. The Lignite Program is codified under N.D. Cent. Code § 54-17.5-01, where the State declares that "North Dakota's lignite industry produces approximately thirty million tons of lignite annually, contributing to the state's and nation's energy independence by generating electricity for more than two million people in the northern great plains region, and by producing synthetic natural gas from coal that heats three hundred thousand homes and businesses in eastern states, which is equivalent to over twenty thousand barrels of oil per day." As such, the North Dakota Legislature finds it "an essential governmental function and public purpose to assist with the development and wise use of North Dakota's vast lignite resources by supporting a lignite research, development, and marketing program that promotes economic, efficient, and clean uses of lignite and products derived from lignite in order to maintain and enhance development of North Dakota lignite and its products." *Id.*

9. One of the programs under the Lignite Program is "Lignite Vision 21," a State-funded program that seeks to facilitate the development of additional new lignite-based energy-conversion facilities in the State of North Dakota. The State offers up to $10 million to match private-sector investment in the early stage development of projects under the Lignite Vision 21 program.

10. One such current development project is the Great Northern Project Development project, which was awarded funding under Lignite Vision 21 to develop a lignite-based energy conversion project in South Heart, North Dakota, where there are considerable reserves of lignite coal. The development group has drafted a mining permit application and is exploring options to develop a permit-able and financeable project, which will consist of evaluating a power system based on gasification of lignite with a shift reactor as the fuel source for a combined cycle system.

11. Any federal regulation that bans new lignite-fueled electric generating units impinges on the Commission's statutory duty to "protect, preserve, and enhance development of North Dakota's abundant lignite resources for the benefit of its citizens." *Id.* § 54-17.5-01. Any such federal regulation also impairs State-funded programs like Lignite Vision 21, which is facilitating the Commission's development of new lignite-fueled facilities like the Great Northern Project Development project.

Executed on October 13, 2016.

Karlene Fine

The foregoing Declaration of Karlene Fine was subscribed and sworn before me by Karlene Fine on October 13th, 2016.

State of North Dakota
County of Burleigh

Witness my hand and official seal.

Vanessa K Kroshus

Notary Public

My commission expires: ________________

VANESSA K. KROSHUS
Notary Public
State of North Dakota
My Commission Expires June 12, 2020

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

STATE OF NORTH DAKOTA

Petitioner,

v.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY,

Respondent.

DECLARATION OF L. DAVID GLATT

Case No. 15-1381

I, L. David Glatt, state and declare as follows:

1. My name is L. David Glatt. I am over 21 years of age and am fully competent and duly authorized to make this Declaration. The facts contained in this Declaration are based on my personal knowledge and are true and correct.

2. I am employed as the Chief of the Environmental Health Section ("EHS") of the North Dakota Department of Health ("Department"). I have been employed by the Department since 1983, and I have continuously served as the Chief of the EHS since 2004.

3. The State of North Dakota, through the Department, implements and enforces the State's various environmental regulatory programs, including federal Clean Air Act ("CAA") programs to implement the New Source Performance Standards ("NSPS"). *See e.g.*, N.D. Cent. Code § 23-25-03. The Department also

oversees State permitting programs for stationary sources under Titles I and V of the CAA. *See Id.* § 23-25-04.1. Additionally, the Department is the technical expert agency that makes all best available control technology ("BACT") determinations under the CAA's New Source Review provisions. *See Id.* § 23-25-01.1; *see also, United States v. Minnkota Power Coop., Inc.*, 831 F. Supp. 2d 1109, 1127 (D.N.D. 2011) (upholding a BACT determination by the Department for lignite-fueled EGUs for nitrogen-oxide emissions based upon detailed consideration of the unique characteristics of North Dakota lignite coal).

4. North Dakota has for decades been aggressive in achieving the first stated purpose of the CAA: "to protect and enhance the quality of the Nation's air resources so as to protect the public health and welfare and the productive capacity of its population." CAA§ 110(b)(1).

5. I am familiar with the final rule promulgated by the U.S. Environmental Protection Agency ("EPA") entitled "Standards of Performance: Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units," 80 Fed. Reg. 64,510 (Oct. 23, 2015) ("Final Rule").

6. In the Final Rule, EPA determined that "a new highly efficient supercritical pulverized coal ("SCPC") boiler implementing partial [carbon capture sequestration]," with sequestration of CO_2 into "deep saline formations," constituted the best system of emission reduction ("BSER") for steam generating units, including those fueled by lignite coal. 80 Fed. Reg. at 64,545. Applying that BSER to new

steam generating units, including those fueled by lignite coal, EPA established a standard of performance for new units of 1,400 pounds of CO_2 per megawatt hour.

7. The Department has evaluated the Final Rule and, as with the proposal, the Department finds no credible evidence that the Rule's BSER is achievable or that a new coal-fired steam generating unit—especially one fueled with North Dakota lignite coal—can achieve the Final Rule's standard of performance of 1,400 pounds of CO_2 per megawatt hour. As a result, the Rule is a *de facto* ban on new coal-fired steam generating units in the State of North Dakota.

8. By effectively banning new coal-fired steam generating units in North Dakota, EPA is improperly becoming a regulator of energy—displacing a traditionally and statutory role held by the states. In North Dakota, the Department is charged with implementing and regulating state and federal air quality programs, as stated above, while the Public Service Commission is charged with regulating electricity. Moreover, the North Dakota Industrial Commission is statutorily charged with researching, development, and advancing lignite coal in the State of North Dakota. In promulgating a Rule that bans the construction of new coal-fired power plants, EPA is going beyond just regulating emissions—it is improperly mandating the types of fuels that can and cannot be used and thus preempting the Department's state permitting function.

9. The Final Rule significantly penalizes North Dakota because it establishes a standard of performance that new EGUs in North Dakota fueled by

both Dakota lignite cannot meet. This results in a *de facto* ban, and the Department consequently cannot evaluate and grant a PSD permits for a new lignite-fueled EGUs.

Executed on October 11, 2016.

L. David Glatt

The foregoing Declaration of L. David Glatt was subscribed and sworn before me by L. David Glatt on October 11, 2016.

Witness my hand and official seal.

SHERRI A. JAHRAUS
Notary Public
State of North Dakota
My Commission Expires Oct. 18, 2020

Sherri A. Jahraus
Notary Public

My commission expires: 10-18-2020