ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[EPA–HQ–OAR–2013–0495; FRL–9987–85–OAR]

RIN 2060–AT56

Review of Standards of Performance for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: The Environmental Protection Agency (EPA) is proposing amendments to the rulemaking titled ''Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units (EGUs),'' which the EPA promulgated by notice dated October 23, 2015 (*i.e.,* the 2015 Rule). Specifically, the EPA proposes to amend its previous determination that the best system of emission reduction (BSER) for newly constructed coal-fired steam generating units (*i.e.,* EGUs) is partial carbon capture and storage (CCS). Instead, the EPA proposes to find that the BSER for this source category is the most efficient demonstrated steam cycle (*e.g.,* supercritical steam conditions for large units and subcritical steam conditions for small units) in combination with the best operating practices. The EPA proposes to revise the standard of performance for newly constructed steam generating units as separate standards of performance for large and small steam generating units that reflect the Agency's amended BSER determination. In addition, the EPA proposes to revise the standard of performance for reconstructed steam generating units to be separate standards of performance for reconstructed large and small steam generating units, consistent with the proposed revised standards for newly constructed steam generating units. The EPA also proposes separate standards of performance for newly constructed and reconstructed coal refuse-fired EGUs. In addition, the EPA proposes to revise the maximally stringent standards for large modifications of steam generating units to be consistent with the standards for reconstructed large and small steam generating units. The EPA is not proposing to amend and is not reopening the standards of performance for newly constructed or reconstructed stationary combustion turbines. The EPA is also proposing to make other miscellaneous technical changes in the regulatory requirements.

DATES: *Comments.* Comments must be received on or before February 19, 2019.

Public Hearing. The EPA is planning to hold at least one public hearing in response to this proposed action. Information about the hearing, including location, date, and time, along with instructions on how to register to speak at the hearing, will be published in a second **Federal Register** notice.

ADDRESSES: *Comments.* Submit your comments, identified by Docket ID No. EPA–HQ–OAR–2013–0495, at *https://www.regulations.gov.* Follow the online instructions for submitting comments. Once submitted, comments cannot be edited or removed from *Regulations.gov.* See **SUPPLEMENTARY INFORMATION** for detail about how the EPA treats submitted comments. *Regulations.gov* is our preferred method of receiving comments. However, other submission methods are accepted:

- *Email: a-and-r-docket@epa.gov.* Include Docket ID No. EPA–HQ–OAR–2013–0495 in the subject line of the message.
- *Fax:* (202) 566–9744. Attention Docket ID No. EPA–HQ–OAR–2013–0495.
- *Mail:* To ship or send mail via the United States Postal Service, use the following address: U.S. Environmental Protection Agency, EPA Docket Center, Docket ID No. EPA–HQ–OAR–2013–0495, Mail Code 28221T, 1200 Pennsylvania Avenue NW, Washington, DC 20460.
- *Hand/Courier Delivery:* Use the following Docket Center address if you are using express mail, commercial delivery, hand delivery, or courier: EPA Docket Center, EPA WJC West Building, Room 3334, 1301 Constitution Avenue NW, Washington, DC 20004. Delivery verification signatures will be available only during regular business hours.

FOR FURTHER INFORMATION CONTACT: For questions about this proposed action, contact Mr. Christian Fellner, Sector Policies and Programs Division (Mail Code D205–01), Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711; telephone number: (919) 541–4003; fax number: (919) 541–4991; and email address: *fellner.christian@epa.gov.*

For information about the applicability of the new source performance standards (NSPS) to a particular entity, contact Sara Ayres, U.S. Environmental Protection Agency, Region 5, 77 West Jackson Boulevard (Mail Code E–19J), Chicago, Illinois 60604–3507; telephone number (312) 353–6266; and email address: *ayres.sara@epa.gov.*

SUPPLEMENTARY INFORMATION:

Docket. The EPA has established a docket for this rulemaking under Docket ID No. EPA–HQ–OAR–2013–0495. All documents in the docket are listed in *Regulations.gov.* Although listed, some information is not publicly available, *e.g.,* confidential business information (CBI) or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the internet and will be publicly available only in hard copy. Publicly available docket materials are available either electronically in *Regulations.gov* or in hard copy at the EPA Docket Center, Room 3334, EPA WJC West Building, 1301 Constitution Avenue NW, Washington, DC. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the EPA Docket Center is (202) 566–1742.

Instructions. Direct your comments to Docket ID No. EPA–HQ–OAR–2013–0495. The EPA's policy is that all comments received will be included in the public docket without change and may be made available online at *https://www.regulations.gov,* including any personal information provided, unless the comment includes information claimed to be CBI or other information whose disclosure is restricted by statute. Do not submit information that you consider to be CBI or otherwise protected through *https://www.regulations.gov* or email. This type of information should be submitted by mail as discussed below.

The EPA may publish any comment received to its public docket. Multimedia submissions (audio, video, *etc.*) must be accompanied by a written comment. The written comment is considered the official comment and should include discussion of all points you wish to make. The EPA will generally not consider comments or comment contents located outside of the primary submission (*i.e.,* on the Web, cloud, or other file sharing system). For additional submission methods, the full EPA public comment policy, information about CBI or multimedia submissions, and general guidance on making effective comments, please visit *https://www.epa.gov/dockets/commenting-epa-dockets.*

The *https://www.regulations.gov* website allows you to submit your comments anonymously, which means the EPA will not know your identity or contact information unless you provide it in the body of your comment. If you send an email comment directly to the EPA without going through *https://www.regulations.gov,* your email address will be automatically captured and included as part of the comment that is placed in the public docket and made available on the internet. If you submit an electronic comment, the EPA recommends that you include your name and other contact information in the body of your comment and with any digital storage media you submit. If the EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, the EPA may not be able to consider your comment. Electronic files should not include special characters or any form of encryption and be free of any defects or viruses. For additional information about the EPA's public docket, visit the EPA Docket Center homepage at *https://www.epa.gov/dockets.*

The EPA is soliciting comment on numerous aspects of the proposed rule. The EPA has indexed each comment solicitation with an alpha-numeric identifier (*e.g.,* ''C–1,'' ''C–2,'' ''C–3,'' . . .) to provide a consistent framework for effective and efficient provision of comments. Accordingly, the EPA asks that commenters include the corresponding identifier when providing comments relevant to that comment solicitation. The EPA asks that commenters include the identifier in either a heading, or within the text of each comment (*e.g.,* ''In response to solicitation of comment C–1, . . .'') to make clear which comment solicitation is being addressed. The EPA emphasizes that the Agency is not limiting comment to these identified areas and encourage provision of any other comments relevant to this proposal.[1]

Submitting CBI. Do not submit information containing CBI to the EPA through *https://www.regulations.gov* or email. Clearly mark the information that you claim to be CBI. For CBI information on any digital storage media that you mail to the EPA, mark the outside of the digital storage media as CBI and then identify electronically within the digital storage media the specific information that is claimed as CBI. In addition to one complete version of the comments that includes information claimed as CBI, you must submit a copy of the comments that does not contain the information claimed as CBI directly to the public docket through the procedures outlined in *Instructions* above. If you submit any digital storage media that does not contain CBI, mark the outside of the digital storage media clearly that it does not contain CBI. Information not marked as CBI will be included in the public docket and the EPA's electronic public docket without prior notice. Information marked as CBI will not be disclosed except in accordance with procedures set forth in 40 Code of Federal Regulations (CFR) part 2. Send or deliver information identified as CBI only to the following address: OAQPS Document Control Officer (C404–02), OAQPS, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711, Attention Docket ID No. EPA–HQ–OAR–2013–0495.

Preamble Acronyms and Abbreviations. The EPA uses multiple acronyms and terms in this preamble. While this list may not be exhaustive, to ease the reading of this preamble and for reference purposes, the EPA defines the following terms and acronyms here:

AEO Annual Energy Outlook
BACT best available control technology
BSER best system of emission reduction
Btu/kWh British thermal units per kilowatt-hour
Btu/lb British thermal units per pound
°C degrees Celsius
CAA Clean Air Act
CAAA Clean Air Act Amendments
CAMD Clean Air Markets Division
CBI confidential business information
CBO Congressional Budget Office
CCS carbon capture and storage (or sequestration)
CEMS continuous emissions monitoring system
CFB circulating fluidized bed
CFR Code of Federal Regulations
CH_4 methane
CHP combined heat and power
CO carbon monoxide
CO_2 carbon dioxide
CSP concentrated solar power
DC District of Columbia
D.C. Circuit United States Court of Appeals for the District of Columbia Circuit
DOE Department of Energy
ECMPS emissions collection and monitoring plan system
EGU electric utility generating unit
EIA U.S. Energy Information Administration
EOR enhanced oil recovery
EPA Environmental Protection Agency
°F degrees Fahrenheit
FB fluidized bed
FGD flue gas desulfurization
FLGR™ fuel lean gas reburning
GHG greenhouse gas
GHGRP Greenhouse Gas Reporting Program
GJ/h gigajoules per hour
GPM gallons per minute
GS geologic sequestration
GW gigawatts
H_2 hydrogen gas
HAP hazardous air pollutant(s)
HFC hydrofluorocarbon
Hg mercury
HRSG heat recovery steam generator
ICR information collection request
IGCC integrated gasification combined cycle
IRPs Integrated Resource Plans
km kilometers
lb CO_2/MMBtu pounds of CO_2 per million British thermal units
lb CO_2/MWh pounds of CO_2 per megawatt-hour
lb CO_2/MWh-gross pounds of CO_2 per megawatt-hour on a gross output basis
lb CO_2/MWh-net pounds of CO_2 per megawatt-hour on a net output basis
LCOE levelized cost of electricity
M million
MMBtu/h million British thermal units per hour
MPa megapascals
MW megawatts
MWh megawatt-hours
MW_{net} megawatts-net
N_2 molecular nitrogen
N_2O nitrous oxide
NAAQS national ambient air quality standards
NAICS North American Industry Classification System
NETL National Energy Technology Laboratory
NGCC natural gas combined cycle
NGR natural gas reburning
NO_X nitrogen oxides
NSPS new source performance standards
NTTAA National Technology Transfer and Advancement Act
O&M operation and maintenance
OAQPS Office of Air Quality Planning and Standards
OFA overfire air
OMB Office of Management and Budget
PC pulverized coal
PFC perfluorocarbon
PM particulate matter
PRA Paperwork Reduction Act
PSD Prevention of Significant Deterioration
psi pounds per square inch
psig pounds per square inch gauge
QA quality assurance
RCRA Resource Conservation and Recovery Act
RFA Regulatory Flexibility Act
SBA Small Business Administration
SCCFB supercritical circulating fluidized bed
SCE&G South Carolina Electric and Gas
SCPC supercritical pulverized coal
SCR selective catalytic reduction
SF_6 sulfur hexafluoride
SO_2 sulfur dioxide
SSM startup, shutdown, and malfunction
T&S transmission and storage
TSD technical support document
UAMPS Utah Associated Municipal Power Systems
$\mu g/m^3$ micrograms per cubic meter
UMRA Unfunded Mandates Reform Act of 1995

[1] In this proposal, in some instances, the EPA identifies an issue that the Agency has previously addressed, and states that the Agency is not re-opening that issue in this proposal. The EPA will not consider such an issue as relevant to this proposal.

U.S. United States
U.S.C. United States Code
VCS voluntary consensus standard

Organization of this Document. The information in this preamble is organized as follows:

I. General Information

A. Executive Summary

1. Proposed Revisions to the 2015 Rulemaking

The EPA is revisiting several portions of the Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units (EGUs), which was promulgated on October 23, 2015 (80 FR 64510). First, for newly constructed fossil fuel-fired electric utility steam generating units that are either utility boilers or integrated gasification combined cycle (IGCC) units, the EPA proposes to revise the BSER to be the most efficient demonstrated steam cycle (*i.e.,* supercritical steam conditions for large EGUs and best available subcritical steam conditions for small EGUs) [2] in combination with the best operating practices, instead of partial CCS. The primary reason for this proposed revision is the high costs and limited geographic availability of CCS. Based on the proposed revisions to the BSER, the EPA is proposing to establish revised (*i.e.,* higher) emission rates as the standards of performance for large and small EGUs (*See* Table 1). Further, for EGUs that undertake a reconstruction, because the standards for reconstructed EGUs are also based on best available efficiency technology, the EPA is proposing to revise those standards to consist of higher emission rates for large and small EGUs to be consistent with the standards for newly constructed EGUs (*See* Table 1). The EPA also proposes separate standards of performance for newly constructed and reconstructed coal refuse-fired EGUs (*See* Table 1). In addition, while the EPA is not proposing to revise the BSER identified in the 2015 Rule (which is based on the individual EGU's best demonstrated performance) for fossil fuel-fired electric utility steam generating units that undertake large modifications [3] (*i.e.,* modifications that result in an increase in hourly emissions of more than 10 percent), the EPA proposes to revise the maximally stringent standards [4] (that is, the level that is the most stringent that the standard can be) to be consistent with the proposed revised standards for new and reconstructed EGUs (*See* Table 1). Additionally, the EPA proposes minor amendments to the applicability criteria for combined heat and power (CHP) and non-fossil EGUs to reflect the original intended coverage. Finally, with respect to EGUs that undertake small modifications (*i.e.,* modifications that result in an increase in hourly emissions of 10 percent or less) for which standards were not included in the 2015 Rule, the EPA is soliciting comment on standards of performance based on a unit's historical performance and how to best account for emissions variability due to changes in the mode of operation (Comment C–1). Table 1 shows the proposed emission standards for newly constructed and reconstructed EGUs, as well as modified EGUs.

[2] A subcritical EGU operates at pressures where water first boils and is then converted to superheated steam. A supercritical steam generator EGU operates at pressures in excess of the critical pressure of water and heats water to produce superheated steam without boiling. While often referred to as a supercritical boiler, no boiling actually occurs in the device and the term ''boiler'' should technically not be used for a supercritical pressure steam generator. *Note:* the term ''EGU'' is intended to refer to the affected facility (also referred to as the affected ''source'' or ''unit'').

[3] Under 40 CFR 60.14(h), a modification of an existing electric utility steam generating unit is defined as a physical change or change in the method of operation of the unit that increases the maximum hourly emissions of any regulated pollutant above the maximum hourly emissions achievable at that unit during the 5 years prior to the change.

[4] The maximally stringent standard for modified EGUs is the numeric standard for reconstructed EGUs, even if the emission rate based on best annual performance is lower than that numeric standard.

TABLE 1—SUMMARY OF BSER AND PROPOSED STANDARDS FOR AFFECTED SOURCES

Affected source	BSER	Emissions standard
New and Reconstructed Steam Generating Units and IGCC Units.	Most efficient generating technology in combination with best operating practices.	1. 1,900 lb CO_2/MWh-gross for sources with heat input >2,000 MMBtu/h. 2. 2,000 lb CO_2/MWh-gross for sources with heat input ≤2,000 MMBtu/h *OR* 3. 2,200 lb CO_2/MWh-gross for coal refuse-fired sources.
Modified Steam Generating Units and IGCC Units.	Best demonstrated performance ..	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 more stringent than: 1. 1,900 lb CO_2/MWh-gross for sources with heat input >2,000 MMBtu/h. 2. 2,000 lb CO_2/MWh-gross for sources with heat input ≤2,000 MMBtu/h *OR* 3. 2,200 lb CO_2/MWh-gross for coal refuse-fired sources.

The EPA is not proposing to amend and is not reopening the standards of performance for newly constructed or reconstructed stationary combustion turbines. The EPA is also proposing to make other miscellaneous technical changes to the regulations.

2. Costs and Benefits

When the EPA promulgated the 2015 Rule, it took note of both utility announcements and U.S. Energy Information Administration (EIA) modeling and, based on that information, concluded that ''even in the absence of this rule, (i) existing and anticipated economic conditions are such that few, if any, fossil-fuel-fired steam-generating EGUs will be built in the foreseeable future,'' and that ''(ii) utilities and project developers are expected to choose new generation technologies (primarily NGCC) that would meet the final standards'' and also ''renewable generating sources that are not affected by these final standards.'' *See* 80 FR 64515. The EPA, therefore, projected that the 2015 Rule would ''result in negligible CO_2 emission changes, quantified benefits, and costs by 2022 as a result of the performance standards for newly constructed EGUs.'' *Id.* The Agency went on to say that it had been ''notified of few power sector NSPS modifications or reconstructions.'' Based on that additional information, the EPA said it ''expects that few EGUs will trigger either the modification or the reconstruction provisions'' of the 2015 Rule. *Id.* at 64516.

The EPA believes that the projections it made in conjunction with its promulgation of the 2015 Rule remain generally correct, in that, as explained in the economic impact analysis for this proposed rule, in the period of analysis, recent EPA and EIA analyses project there to be, at most, few new, reconstructed, or modified sources that will trigger the provisions the EPA is proposing. Consequently, the EPA has conducted an illustrative analysis of the costs for a representative new unit. Based on this analysis, which is presented in the economic impact analysis, the EPA projects this proposed rule will not result in any significant carbon dioxide (CO_2) emission changes or costs. This analysis reflects the best data available to the EPA at the time the modeling was conducted. As with any modeling of future projections, many of the inputs are uncertain. In this context, notable uncertainties, in the future, include the cost of fuels, the cost to operate existing power plants, the cost to construct and operate new power plants, infrastructure, demand, and policies affecting the electric power sector. The modeling conducted for this economic impact analysis is based on estimates of these variables, which were derived from the data currently available to the EPA. However, future realizations could deviate from these expectations as a result of changes in wholesale electricity markets, federal policy intervention, including mechanisms to incorporate value for onsite fuel storage, or substantial shifts in energy prices. The results presented in this economic impact analysis are not a prediction of what will happen, but rather a projection describing how this proposed regulatory action may affect electricity sector outcomes in the absence of unexpected shocks. The results of this economic impact analysis should be viewed in that context.

B. Types of Sources

Fossil fuel-fired EGUs take two forms that are relevant for present purposes: Those that are steam generating units and those that use gasification technology.[5] Fossil fuel-fired steam generating units can burn natural gas, oil, or coal. However, coal is the dominant fuel for electric utility steam generating units. Coal-fired steam generating units are primarily either pulverized coal (PC) or fluidized bed (FB) steam generating units.[6] At a PC steam generating unit, the coal is crushed (pulverized) into a powder to increase its surface area. The coal powder is then blown into a steam generating unit and burned. In a fossil fuel-fired steam generating unit using FB combustion, the solid fuel is burned in a layer of heated particles suspended in flowing air. Power can also be generated from coal or other fuels using gasification technology. An IGCC unit gasifies coal or petroleum coke to form a synthetic gas (or syngas) composed of carbon monoxide (CO) and hydrogen (H_2), which can be combusted in a combined cycle system to generate power.

Natural gas-fired EGUs typically use one of two technologies: Natural gas combined cycle (NGCC) or simple cycle combustion turbines. NGCC units first generate power from a combustion turbine engine (the combustion cycle).[7] The unused heat from the combustion turbine engine is then routed to a heat recovery steam generator (HRSG) that generates steam, which is then used to produce power using a steam turbine (the steam cycle). Combining these generation cycles increases the overall efficiency of the system. Simple cycle combustion turbines only use a combustion turbine engine to produce

[5] Fossil fuel-fired EGUs also include combustion turbines, but the EPA is not proposing any changes to standards for those types of sources in this rulemaking.

[6] Fossil fuel-fired utility steam generating units (*i.e.,* boilers) are most often operated using coal as the primary fuel. However, some utility boilers use natural gas and/or fuel oil as the primary fuel.

[7] Note that natural gas can also be used as a fuel in a steam generating EGU (boiler) and many existing coal- and oil-fired utility boilers have repowered as natural gas-fired units. However, a natural gas-fired utility boiler is not currently an economically or technologically viable choice for construction of a new steam generating unit EGU (80 FR 64515).

electricity (*i.e.,* there is no heat recovery or steam cycle).

C. The 2015 Rulemaking, Reconsideration, and Litigation

On April 13, 2012, the EPA first proposed a NSPS for greenhouse gas (GHG) emissions from fossil fuel-fired EGUs (77 FR 22392). That proposal identified as the BSER for a coal-fired power plant building a natural gas-fired power plant (*Id.* at 22394). On January 8, 2014, the EPA rescinded that proposal and replaced it with a supplemental proposal that identified partial CCS as the BSER for coal-fired power plants [8] (79 FR 1430). On October 23, 2015, the EPA finalized the Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Generating Units (80 FR 64510). In that action, the EPA issued final standards of performance to limit emissions of GHG pollution manifested as CO_2 [9] from newly constructed, modified, and reconstructed fossil fuel-fired electric utility steam generating units (*i.e.,* utility boilers and IGCC EGUs) and newly constructed and reconstructed stationary combustion turbine EGUs. These final standards are codified in 40 CFR part 60, subpart TTTT.

The 2015 standards of performance for newly constructed fossil fuel-fired steam generating units [10] were based on the performance of a new, highly efficient, supercritical pulverized coal (SCPC) EGU, implementing post-combustion partial CCS technology, which the EPA determined to be the BSER under Clean Air Act (CAA) section 111(b) for these sources. The EPA concluded that CCS was adequately demonstrated (including being technically feasible) and widely available, and could be implemented at reasonable cost. The EPA did not determine natural gas co-firing or IGCC technology (either with natural gas co-firing or implementing partial CCS) to be BSER. However, the Agency did identify them as alternative methods of compliance.

The EPA also issued final standards for steam generating units that implement ''large modifications,'' (*i.e.,* modifications resulting in an increase in hourly CO_2 emissions of more than 10 percent). The standards of performance for modified steam generating units that make large modifications are based on each affected unit's own best historical performance as the BSER. The EPA did not issue final standards for steam generating units that implement ''small modifications'' (*i.e.,* modifications resulting in an increase in hourly CO_2 emissions of less than or equal to 10 percent).

For steam generating units that undergo a ''reconstruction'' (*i.e.,* the replacement of components of an existing EGU to an extent that both: (1) The fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new EGU, and (2) it is technologically and economically feasible to meet the applicable standards),[11] the EPA finalized standards based on the performance of the most efficient generating technology for these types of units as the BSER (*i.e.,* reconstructing the boiler as necessary to use steam with higher temperature and pressure, even if the boiler was not originally designed to do so).[12] The 2015 emission standard for large EGUs (greater than approximately 200 megawatts (MW)) was based on the performance of a well-operated PC EGU using supercritical steam conditions. The emission standard for small EGUs (less than approximately 200 MW) was based on the performance of a well-operated PC using the best available subcritical steam conditions. The difference in the standards for larger and smaller EGUs was based on the commercial availability of higher pressure/temperature steam turbines (*e.g.,* supercritical steam turbines) for large EGUs. While it is technically possible to design smaller supercritical steam turbines, due to the lack of commercial availability, the EPA was not able to access sufficient information regarding the cost of developing a specially designed steam turbine to determine that this was appropriate for inclusion as BSER.

The EPA has historically been notified of only a limited number of NSPS modifications involving fossil fuel-fired steam generating units. *See* Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units—Proposed Rule, 77 FR 22392, 22400 (April 13, 2012). Given the limited information, the Agency concluded during the 2015 rulemaking that it lacked sufficient information to establish standards of performance for all types of modifications at steam generating units. Instead, the EPA determined that it was appropriate to establish standards of performance only for affected modified steam generating units that undergo modifications resulting in an hourly increase in CO_2 emissions (mass per hour) of more than 10 percent (''large'' modifications) as compared to the source's highest hourly emission during the previous 5 years. The Agency determined that it had adequate information regarding the types of large, capital-intensive projects [13] that could result in large increases in hourly CO_2 emissions. Additionally, the Agency determined that it had adequate information regarding the types of measures available to control emissions from sources that undergo such modifications, and on the costs and effectiveness of such control measures. The EPA determined that the BSER for steam generating units that trigger the large modification provision is each affected unit's own best historic annual CO_2 emission rate (from 2002 to the date of the modification).

With respect to affected steam generating units that undergo modifications that result in smaller increases in CO_2 emissions (specifically, steam generating units that conduct modifications resulting in an increase in hourly CO_2 emissions (mass per hour) of 10 percent or less (''small'' modifications) compared to the source's highest hourly emission during the previous 5 years), the EPA concluded it did not have sufficient information and did not finalize any standard of performance or other requirements. The EPA continues to review whether it has sufficient information to establish appropriate standards for small modifications and is soliciting comment on options for determining appropriate standards in this action (Comment C–2).

[8] The applicability includes all fossil fuel-fired steam generating units (*e.g.,* natural gas and oil-fired EGUs), but the BSER determination focused on coal-fired EGUs.

[9] Greenhouse gas pollution is the aggregate group of the following gases: CO_2, methane (CH_4), nitrous oxide (N_2O), sulfur hexafluoride (SF_6), hydrofluorocarbons (HFCs), and perfluorocarbons (PFCs).

[10] The EPA also refers to fossil fuel-fired steam generating units as ''steam generating units'' or as ''utility boilers and IGCC units.'' These are units whose emission of criteria pollutants are covered under 40 CFR part 60, subpart Da. Criteria pollutants are those for which the EPA issues health criteria pursuant to CAA section 108, issues national ambient air quality standards (NAAQS) pursuant to CAA section 109, promulgates area designations of attainment, nonattainment, or unclassifiable pursuant to CAA section 107, and reviews and approves or disapproves state implementation plan (SIP) submissions and issues federal implementation plans (FIPs) pursuant to CAA section 110. GHG are not criteria pollutants.

[11] 40 CFR 60.15.

[12] Steam with higher temperature and pressure has more thermal energy that can be more efficiently converted to electrical energy.

[13] Major facility upgrades involving the refurbishment or replacement of steam turbines or other equipment upgrades that could significantly increase an EGU's capacity to burn more fossil fuel, thereby resulting in a large emissions increase.

The 2015 Rule also finalized standards of performance for newly constructed and reconstructed stationary combustion turbine EGUs. For newly constructed and reconstructed base load natural gas-fired stationary combustion turbines, the EPA finalized a standard based on efficient NGCC technology as the BSER. For newly constructed and reconstructed non-base load natural gas-fired and multi-fuel-fired (both base load and non-base load) stationary combustion turbines, the EPA finalized a heat input-based clean fuels standard. The EPA did not promulgate final standards of performance for modified stationary combustion turbines due to lack of information.

The EPA received six petitions for reconsideration of the 2015 final CAA section 111(b) GHG NSPS rule. The EPA denied five of the petitions on the basis they did not satisfy one or both of the statutory conditions for reconsideration under CAA section 307(d)(7)(B), and deferred action on a petition that raised the issue of the treatment of biomass on May 6, 2016 (81 FR 27442). Multiple parties also filed petitions for judicial review of the 2015 Rule. These petitions were consolidated into a single case and the petitioners filed opening written briefs in October 2016. The EPA and supporting intervenors filed opening written briefs in December 2016. Next, petitioners submitted written reply briefs in January 2017. On April 28, 2017, the United States Court of Appeals for the District of Columbia granted the EPA's motion to hold the cases in abeyance while the Agency reviews the 2015 Rule and considers whether to propose revisions to it.

D. The Purpose of This Regulatory Action

Executive Order 13783 (Promoting Energy Independence and Economic Growth) directs all executive departments and agencies, including the EPA, to ''immediately review existing regulations that potentially burden the development or use of domestically produced energy resources and appropriately suspend, revise, or rescind those that unduly burden the development of domestic energy resources beyond the degree necessary to protect the public interest or otherwise comply with the law.'' [14] Moreover, the Executive Order directs the EPA to undertake this process of review with regard to the New Source Rule issued under CAA section 111(b).

In a document signed the same day as Executive Order 13783 and published in the **Federal Register** at 82 FR 16330 (April 4, 2017), the EPA announced that, consistent with the Executive Order, it was initiating its review of the Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Generating Units, and providing notice of forthcoming proposed rulemakings consistent with the Executive Order. As explained below, that review has led the EPA to propose to revise the BSER determinations for new, reconstructed, and modified coal-fired EGUs, including reconsideration issues previously denied by the Agency.

E. Does this action apply to me?

Table 2 of this preamble lists the regulated industrial source categories that are the subject of this proposal. Table 2 is not intended to be exhaustive, but rather provides a guide for readers regarding the entities that this proposed action is likely to affect. The proposed standards, once promulgated, will be directly applicable to the affected sources. To determine whether your facility, company, business, organization, *etc.,* would be regulated by this proposed action, you should examine the applicability criteria in 40 CFR 60.1. If you have questions regarding the applicability of this action to a particular entity, consult either the air permitting authority for the entity or your EPA Regional representative as listed in 40 CFR 60.4 (General Provisions).

TABLE 2—INDUSTRIAL SOURCE CATEGORIES AFFECTED BY THIS PROPOSED ACTION

Category	NAICS code [1 2]	Examples of regulated entities
Industry	221112	Fossil fuel electric power generating units.
Federal government	[3] 221112	Fossil fuel electric power generating units owned by the federal government.
State/local government	[3] 221112	Fossil fuel electric power generating units owned by municipalities.
Tribal government	921150	Fossil fuel electric power generating units in Indian Country.

[1] North American Industry Classification System.
[2] Includes NAICS codes for source categories that own and operate electric power generating units (including boilers and stationary combined cycle combustion turbines).
[3] Federal, state, or local government-owned and operated establishments are classified according to the activity in which they are engaged.

F. Where can I get a copy of this document and other related information?

In addition to being available in the docket, an electronic copy of this action is available on the internet. Following signature by the Administrator, the EPA will post a copy of this proposed action at *https://www.epa.gov/stationary-sources-air-pollution/proposal-nsps-ghg-emissions-new-modified-and-reconstructed-egus.* Following publication in the **Federal Register**, the EPA will post the **Federal Register** version of the proposal and key technical documents at this same website.

A version of the regulatory language that incorporates the proposed changes in this action in track changes (*i.e.,* redline) is available in the docket for this action (Docket ID No. EPA–HQ–OAR–2013–0495).

II. Proposed Requirements for New, Reconstructed, and Modified Sources

A. Applicability Requirements

The EPA identified the applicability requirements for the 40 CFR part 60, subpart TTTT standards in the 2015 rulemaking, and the Agency is not proposing to revise or reopening those requirements, except as noted below. Those requirements are as follows: In general, the EPA refers to fossil fuel-fired electric generating units that would be subject to a CAA section 111 emission standard as ''affected'' EGUs or units. An EGU is any fossil fuel-fired electric utility steam generating unit (*i.e.,* a utility boiler or IGCC unit) or combustion turbine (in either simple cycle or combined cycle configuration). To be considered an affected EGU under 40 CFR part 60, subpart TTTT, the unit must meet the following applicability criteria: The unit must both: (i) Be

[14] *Id.,* Section 1(c).

capable of combusting more than 250 million British thermal units per hour (MMBtu/h) (260 gigajoules per hourA (GJ/h)) of heat input of fossil fuel (either alone or in combination with any other fuel); [15] and (ii) serve a generator capable of supplying more than 25 MW net to a utility distribution system (*i.e.,* for sale to the grid).[16] However, 40 CFR part 60, subpart TTTT includes applicability exemptions for certain EGUs, including: (1) Non-fossil fuel units subject to a federally enforceable permit that limits the use of fossil fuels to 10 percent or less of their heat input capacity on an annual basis; (2) CHP units that are subject to a federally enforceable permit limiting annual net electric sales to no more than either the unit's design efficiency multiplied by its potential electric output, or 219,000 megawatt-hours (MWh), whichever is greater; (3) stationary combustion turbines that are not physically capable of combusting natural gas (*e.g.,* those that are not connected to a natural gas pipeline); (4) utility boilers and IGCC units that have always been subject to a federally enforceable permit limiting annual net electric sales to one-third or less of their potential electric output (*e.g.,* limiting hours of operation to less than 2,920 hours annually) or limiting annual electric sales to 219,000 MWh or less; (5) municipal waste combustors that are subject to 40 CFR part 60, subpart Eb; (6) commercial or industrial solid waste incineration units subject to 40 CFR part 60, subpart CCCC; and (7) certain projects under development, as discussed below.

The CAA defines a new or modified source for purposes of a given regulation as any stationary source that commences construction or modification after the publication of the proposed regulation. Thus, any standards of performance the Agency finalizes as part of this rulemaking will apply to EGUs that commence construction, reconstruction, or modification after the date of this proposal. (EGUs that commenced construction after the date of the proposal for the 2015 Rule and before the date of this proposal will remain subject to the standards of performance promulgated in that Rule.) A modification is any physical change in, or change in the method of operation of an existing source that increases the amount of any air pollutant emitted to which a standard applies.[17] The NSPS General Provisions (40 CFR part 60 subpart A) provide that an existing source is considered a new source if it undertakes a reconstruction.[18]

The EPA is proposing several changes to the applicability requirements. First, the EPA is proposing to change the exemption from applicability for EGUs (item 1 on the list above) on the grounds that they are considered non-fossil-fuel EGUs by revising the definition of non-fossil fuel EGUs from EGUs capable of ''combusting 50 percent or more non-fossil fuel'' to EGUs capable of ''*deriving* 50 percent or more *of the heat input* from non-fossil fuel *at the base load rating.*'' (emphasis added). This amendment is consistent with the original intent to cover only fossil fuel EGUs and would assure that solar thermal EGUs with natural gas backup burners, which are similar to other types of non-fossil fuel units in that most of their energy is derived from non-fossil fuel sources, are not subject to the requirements of 40 CFR part 60, subpart TTTT. The definition of base load rating would also be amended to include the heat input from non-combustion sources (*e.g.,* solar thermal). Next, the design efficiency of an EGU is used to determine the electric sales applicability threshold. 40 CFR part 60, subpart TTTT currently allows the use of three methods for determining the design efficiency.[19] To reduce compliance burden, the EPA is proposing to allow alternative methods as approved by the Administrator on a case-by-case basis.[20] The EPA is also proposing to change the applicability of paragraph 60.8(b) in Table 3 of subpart TTTT from no to yes. This amendment would allow the Administrator to approve alternatives to the test methods specified in subpart TTTT. Finally, to avoid potential double counting of electric sales, the EPA is proposing that for CHP units determining net electric sales, purchased power of the host facility would be determined based on the percentage of thermal power provided to the host facility by the specific CHP facility. If any of these amendments are not finalized, EGUs that would be exempted by the proposed amendments would remain subject to 40 CFR part 60, subpart TTTT.

B. Emission Standards

In this action, the EPA proposes revisions to the 2015 Rule's provisions for newly constructed coal-fired electric utility steam generating units (both utility boilers and IGCC units). The EPA proposes to revise its previous determination that the BSER for such newly constructed EGUs is partial CCS. The EPA bases this revision on (1) an updated analysis of what represents reasonable costs and (2) an updated analysis of the geographic availability of CCS. In addition, the EPA solicits comment on the technical feasibility of carbon capture technologies. Instead, the EPA proposes to create three subcategories of steam generating units: Large units, defined as units with heat input greater than 2,000 MMBtu/h; small units, defined as units with heat input less than or equal to 2,000 MMBtu/h; and units of any size (that meet the applicability criteria) and that are fired with coal refuse. The EPA proposes to find that for each of these subcategories, the BSER is the most efficient demonstrated steam cycle (*i.e.,* supercritical steam conditions for large units and best available subcritical steam conditions for small and coal refuse-fired units) in combination with the best operating practices. Unless stated otherwise, the EPA's use of the term supercritical steam conditions, or, more simply, supercritical, encompasses both ultra-supercritical and advanced ultra-supercritical steam conditions. There is no thermodynamic definition of ultra-supercritical or advanced ultra-supercritical steam conditions; rather, they are terms used to define subsets of supercritical steam conditions with higher temperatures and pressures.[21] The EPA is proposing revised standards of performance for newly constructed steam units in the three subcategories that reflect the Agency's proposed BSER determinations: 1,900 pounds of CO_2 per MWh of gross output (lb CO_2/MWh-gross) for large EGUs; 2,000 lb CO_2/MWh-gross for small EGUs, and 2,200 lb CO_2/MWh-gross for coal refuse-fired units.[22] The EPA is not proposing to

[15] The EPA refers to the capability to combust 250 MMBtu/h of fossil fuel as the ''base load rating criterion.'' Note that 250 MMBtu/h is equivalent to 73 MW or 260 GJ/h heat input.

[16] The EPA refers to the capability to supply 25 MW net to the grid as the ''total electric sales criterion.''

[17] 40 CFR 60.2.

[18] 40 CFR 60.15(a).

[19] Subpart TTTT currently lists ASME PTC 22 Gas Turbines, ASME PTC 46 Overall Plant Performance, and ISO 2314 Gas turbines—acceptance tests as approved methods to determine the design efficiency.

[20] Owners/operators of EGUs would petition the Administrator is writing to use an alternate method to determine the design efficiency. Administrator discretion is intentionally left broad and could include other ASME or ISO methods as well as data to demonstrate the design efficiency of the EGU.

[21] Supercritical, ultra-supercritical, and advanced ultra-supercritical steam generators operate at pressures greater than 22 megapascals (MPa) (3,205 pounds per square inch (psi)), temperatures greater than 550 degrees Celsius (°C) (1,022 degrees Fahrenheit (°F)), and use the same general steam generating unit design. The primary difference is that different materials are required to withstand the higher temperatures of ultra-supercritical and advanced ultra-supercritical steam conditions.

[22] In contrast, in the 2015 Rule, the EPA did not create any subcategories for new steam generating units.

revise its view in the 2015 Rule that natural gas co-firing and IGCC are alternate control technologies, but as described in section V.B of this preamble, not the BSER. The EPA invites the public to identify any additional information not considered by the Agency in the BSER analysis. (Comment C–3)

In addition, in this action, the EPA proposes to revise the 2015 Rule's standard of performance for reconstructed EGUs to be consistent with the numeric standards for new EGUs. By the same token, with respect to modified EGUs, the EPA proposes to revise the 2015 Rule's maximally stringent emissions rate for large modifications to be the same as the standards for newly constructed and reconstructed units in the same three subcategories (*e.g.,* while the standard would continue to be based on looking at average historical data, the EPA is proposing that the standard can be no lower than the new source standard). While the EPA is proposing revisions to the maximally stringent emission standards, the Agency is not proposing to revise or reopening the 2015 Rule's BSER determination, which was the use of the most efficient generation available in combination with best operating practices, based on historical emissions, or the associated standard of performance. The EPA is soliciting comment on standards of performance for "small" modifications based on a unit's best demonstrated historical performance and the most appropriate approach to account for emissions variability due to changes in the mode of operation and other factors (Comment C–4).

The EPA is not proposing to revise or reopening the 2015 Rule's requirement that the emission standards applicable to any type of EGU (however they may be revised in a final action on this proposal) apply at all times, including during periods of startup, shutdown, and malfunction (SSM). In addition, in this action, the EPA is not proposing to revise or reopening the air pollutants covered by the 2015 Rule or any of the Rule's continuous monitoring requirements; emissions performance testing requirements; continuous compliance requirements; or notification, recordkeeping, and reporting requirements. Furthermore, the EPA is not proposing to amend or reopening the 2015 Rule's BSER determination or standards of performance for new or reconstructed stationary combustion turbines.

Table 3 below summarizes the proposed standards of performance for three proposed subcategories of newly constructed and reconstructed EGUs as well as the proposed maximally stringent standards for modified EGUs. Consistent with the 2015 rulemaking, these emission standards would apply on a 12-operating month rolling average.

TABLE 3—SUMMARY OF BSER AND PROPOSED STANDARDS FOR AFFECTED SOURCES

Affected source	BSER	Emissions standard
New and Reconstructed Steam Generating Units and IGCC Units.	Most efficient generating technology in combination with best operating practices.	1. 1,900 lb CO_2/MWh-gross for sources with heat input >2,000 MMBtu/h. 2. 2,000 lb CO_2/MWh-gross for sources with heat input ≤2,000 MMBtu/h *OR* 3. 2,200 lb CO_2/MWh-gross for coal refuse-fired sources.
Modified Steam Generating Units and IGCC Units.	Best demonstrated performance ..	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 more stringent than 1. 1,900 lb CO_2/MWh-gross for sources with heat input >2,000 MMBtu/h. 2. 2,000 lb CO_2/MWh-gross for sources with heat input ≤2,000 MMBtu/h *OR* 3. 2,200 lb CO_2/MWh-gross for coal refuse-fired sources.

The EPA is proposing that the amended emission standards apply to any EGUs that commence construction, reconstruction, or modification after December 20, 2018. The EPA is not aware of any coal fuel-fired EGUs that have commenced construction, reconstruction, or modification since January 8, 2014 (the applicability date of 40 CFR part 60, subpart TTTT). Therefore, no existing units would be impacted by the proposed revised BSER determination.

III. Legal Authority

A. Statutory Background

This action is governed by CAA section 111, which authorizes and directs the EPA to prescribe NSPS applicable to certain new stationary sources (including newly constructed, modified, and reconstructed sources).[23] As a preliminary step to regulation, the EPA lists categories of stationary sources that the Administrator, in his or her judgment, finds "cause, or contribute significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare." the EPA has listed and regulated more than 60 stationary source categories under CAA section 111.[24]

The EPA's authority for this proposed rule is CAA section 111(b)(1). In both the 2015 Rule and the 2014 proposed rule, the EPA discussed the requirements of that provision and why the Rule met them. *See* 80 FR 64510, 64529–31 (2015 Rule), 79 FR 1430, 1455 (January 8, 2014) (2014 proposed rule). In summary, CAA section 111(b)(1)(A) requires the Administrator to establish a list of source categories to be regulated under CAA section 111. A category of sources is to be included on the list "if in [the Administrator's] judgment it causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health and welfare." This determination is commonly referred to as an "endangerment finding" and that phrase encompasses both the "causes or contributes significantly" component and the "endanger public health and welfare" component of the determination. Once the Administrator lists a source category under CAA section 111(b)(1)(A), he or she then promulgates, under CAA section 111(b)(1)(B), "standards of performance for new sources within such category."

In the 2015 Rule, the EPA promulgated standards for CO_2 emissions from sources in two source categories, fossil fuel-fired electric utility steam generating units and combustion turbines. In the 2015 Rule,

[23] CAA section 111(b)(1)(A).

[24] *See* generally 40 CFR part 60, subparts D–MMMM.

the EPA explained that the Agency interprets the statute to require an endangerment finding to be made at the time the EPA lists the source category and to broadly concern emissions from the source category, and not to concern emissions of any particular pollutant that may be made subject to a revised or newly issued standard for a source category that has already been listed. The EPA further explained that CAA section 111(b) does not specify what pollutants the EPA should regulate once it lists a source category, so that the EPA may exercise its discretion to regulate particular pollutants as long as the EPA provides a rational basis for doing so. *See National Lime Ass'n* v. *EPA,* 627 F.2d 416, 431–32 n.48 (D.C. Cir. 1980).

In the 2015 Rule, the EPA described its rational basis for regulating CO_2 emissions from fossil fuel-fired EGUs, including that the CO_2 emissions from fossil fuel-fired EGUs are almost three times as much as the emissions from the next 10 source categories combined, and that the CO_2 emissions from even a single new coal-fired power plant may amount to millions of tons each year. The EPA added that even if it were required to make an endangerment finding for those emissions in order to regulate them, the same facts that provided the rational basis would qualify as an endangerment finding.[25]

A ''new source'' is ''any stationary source, the construction or modification of which is commenced after,'' in general, final standards applicable to that source are promulgated or, if earlier, proposed.[26] A modification is ''any physical change . . . or change in the method of operation . . . 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'' to which the standard applies.[27] The EPA, through regulations, has determined that certain types of changes are exempt from consideration as a modification.[28] The EPA ''may distinguish among classes, types and sizes within categories of new sources for the purpose of establishing such standards.'' *See* CAA section 111(b)(2).

The NSPS General Provisions (40 CFR part 60, subpart A) provides that an existing source is considered to be a new source if it undertakes a ''reconstruction,'' which is the replacement of components of an existing EGU to an extent that both (1) the fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new EGU, and (2) it is technologically and economically feasible to meet the applicable standards.[29]

Congress first enacted the definition of ''standard of performance'' as part of CAA section 111 in the 1970 Clean Air Act Amendments (CAAA), amended it in the 1977 CAAA, and amended it again in the 1990 CAAA to largely restore the original definition as it read in the 1970 CAAA. It is in the legislative history for the 1970 and 1977 CAAAs that Congress primarily addressed the definition as it read in those two versions of the statute, and that legislative history provides guidance in interpreting this provision.[30] In addition, the U.S. Court of Appeals for the D.C. Circuit has reviewed rulemakings under CAA section 111 on numerous occasions during the past 40 years, issuing decisions dated from 1973 to 2011,[31] through which the Court has developed a body of case law that interprets the term ''standard of performance.''

Section 111(b) of the CAA authorizes the EPA to set ''standards of performance'' for new, reconstructed, and modified stationary sources from listed source categories to minimize emissions of air pollutants to the environment. Under CAA section 111(a)(1), the EPA must set these standards at the level that reflects the ''best system of emission reduction . . . adequately demonstrated'' taking into account technical feasibility, costs, and non-air quality health and environmental impacts and energy requirements.[32] The text and legislative

[25] The EPA is proposing to retain the statutory interpretations and record determinations described in this paragraph. Nonetheless, the EPA is aware that various stakeholders have in the past made arguments opposing our views on these points, and the Agency sees value to allowing them to comment on these views in this rulemaking. Accordingly, the Agency will consider comments on the correctness of the EPA's interpretations and determinations and whether there are alternative interpretations that may be permissible, either as a general matter or specifically as applied to GHG emissions. For example, the Agency will consider comments on the issue of whether it is correct to interpret the ''endangerment finding'' as a finding that is only made once for each source category at the time that the EPA lists the source category or whether the EPA must make a new endangerment finding each time the Agency regulates an additional pollutant by an already-listed source category. Further, the EPA will consider comments on the issue of whether GHG emissions are different in salient respects from traditional emissions such that it would be appropriate to conduct a new ''endangerment finding'' with respect to GHG emissions from a previously listed source category. In addition, the EPA solicits comment on whether the Agency does have a rational basis for regulating CO_2 emissions from new coal-fired electric utility steam generating units and whether it would have a rational basis for declining to do so at this time, in light of, among other things, the following: (i) Ongoing and projected power sector trends that have reduced CO_2 emissions from the power sector, EIA, *Annual Energy Outlook 2018 with projections to 2050* (February 6, 2018), at 102, available at *https://www.eia.gov/outlooks/aeo/pdf/AEO2018.pdf,* due to reduced coal-fired generation, as the EPA discusses in the proposed Affordable Clean Energy rule, 83 FR 44746, 44750–51 (August 31, 2018); and (ii) as noted above, no more than a few new coal-fired EGUs can be expected to be built, which raises questions about whether new coal-fired EGUs contribute significantly to atmospheric CO_2 levels.

[26] CAA section 111(a)(2).

[27] CAA section 111(a)(4). *See* also 40 CFR 60.14 (concerning what constitutes a modification, how to determine the emission rate, how to determine an emission increase, and exempting specific actions that are not, by themselves, considered modifications).

[28] 40 CFR 60.2, 60.14(e).

[29] 40 CFR 60.15.

[30] In the 1970 CAAA, Congress defined ''standard of performance,'' under CAA section 111(a)(1), as—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) the Administrator determines has been adequately demonstrated.

In the 1977 CAAA, Congress revised the definition to distinguish among different types of sources, and to require that for fossil fuel-fired sources, the standard: (i) Be based on, in lieu of the ''best system of emission reduction . . . adequately demonstrated,'' the ''best *technological* system of continuous emission reduction . . . adequately demonstrated'' (emphasis added); and (ii) require a specific percentage reduction in emissions. In addition, in the 1977 CAAA, Congress expanded the parenthetical requirement that the Administrator consider the cost of achieving the reduction to also require the Administrator to consider ''any non-air quality health and environment impact and energy requirements.''

In the 1990 CAAA, Congress again revised the definition, this time repealing the requirements that the standard of performance be based on the best technological system and achieve a percentage reduction in emissions, and replacing those provisions with the terms used in the 1970 CAAA version of CAA section 111(a)(1) that the standard of performance be based on the ''best system of emission reduction . . . adequately demonstrated.'' This 1990 CAAA version is the current definition. Even so, because parts of the definition as it read under the 1977 CAAA were retained in the 1990 CAAA, *see* CAA section 111(a)(1), the explanation in the 1977 CAAA legislative history, and the interpretation in the case law, of those parts of the definition in the case law remain relevant to the definition as it reads currently.

[31] *Portland Cement Ass'n* v. *Ruckelshaus,* 486 F.2d 375 (D.C. Cir. 1973); *Essex Chemical Corp.; Portland Cement Ass'n* v. *EPA,* 665 F.3d 177 (D.C. Cir. 2011). *See* also *Delaware* v. *EPA,* No. 13–1093 LEXIS CITE (D.C. Cir. May 1, 2015).

[32] The standard that EPA develops, reflecting the performance of the BSER, commonly takes the form of a numeric emission limit, expressed as a numeric performance level that can either be normalized to a rate of output or input (*e.g.,* tons of pollution per amount of product produced—a so-called rate-based standard), or expressed as a numeric limit on mass of pollutant that may be emitted (*e.g.,* 100 micrograms per cubic meter ($\mu g/m^3$)—or parts per billion). Generally, the EPA does not prescribe a particular technological system that must be used to comply with a standard CAA section 111(b)(5) and (h). Rather, sources generally may select any measure or combination of measures that will achieve the emissions level of the standard of performance. CAA section 111(b)(5). In establishing standards of performance, EPA has significant discretion to create subcategories based on source type, class, or size. CAA section 111(b)(2); *see* also

history of CAA section 111, the EPA's regulatory interpretations of that provision, and relevant court decisions, identify factors for the EPA to consider in making a BSER determination. They include, among others, whether the system of emission reduction is technically feasible, whether the costs of the system are reasonable, the amount of emissions reductions the system would generate,[33] and whether the standard would effectively promote further deployment or development of advanced technology.[34]

The overall approach to determining the BSER, which incorporates the various elements, is as follows: First, the EPA identifies the ''system[s] of emission reduction'' that have been ''adequately demonstrated'' for a particular source category. Second, the EPA determines the ''best'' of these systems after evaluating the extent of emission reductions, costs, any non-air health and environmental impacts, and energy requirements. Third, the EPA selects an achievable standard for emissions—here, the emission rate—based on the performance of the BSER. The remainder of this subsection discusses the various elements in that analytical approach.

1. ''System[s] of Emission Reduction . . . Adequately Demonstrated''

The EPA's first step is to identify ''system[s] of emission reduction . . . adequately demonstrated.'' An ''adequately demonstrated'' system, according to the D.C. Circuit, is ''one which has been shown to be reasonably reliable, reasonably efficient and which can reasonably be expected to serve the interests of pollution control without becoming exorbitantly costly in an economic or environmental way.'' [35] It does not mean that the system ''must be in actual routine use somewhere.'' [36] Rather, the Court has said, ''[t]he Administrator may make a projection based on existing technology, though that projection is subject to the restraints of reasonableness and cannot be based on 'crystal ball' inquiry.'' [37] The EPA has previously explained that the requirement that the standard for emissions be ''achievable'' based on the ''best system of emission reduction . . . adequately demonstrated'' indicates that one of the requirements for the technology or other measures that the EPA identifies as the BSER is that the measure must be technically feasible (81 FR 64538).

2. ''Best''

In determining which adequately demonstrated system of emission reduction is the ''best,'' the EPA considers the following factors:

a. Costs

Under CAA section 111(a)(1), the EPA is required to take into account ''the cost of achieving'' the required emission reductions. In several cases, the D.C. Circuit has elaborated on this cost factor and formulated the cost standard in various ways, stating that the EPA may not adopt a standard the cost of which would be ''exorbitant,'' [38] ''greater than the industry could bear and survive,'' [39] ''excessive,'' [40] or ''unreasonable.'' [41] As the EPA has explained in a prior rulemaking, for convenience, the EPA uses ''reasonableness'' to describe costs well within the bounds established by this jurisprudence.

The D.C. Circuit has indicated that the EPA has substantial discretion in its consideration of cost under CAA section 111(a). In several cases, the Court upheld standards that entailed significant costs, consistent with Congress's view that ''the costs of applying best practicable control technology be considered by the owner of a large new source of pollution as a normal and proper expense of doing business.'' [42] *See Essex Chemical Corp.* v. *Ruckelshaus,* 486 F.2d 427, 440 (D.C. Cir. 1973), *cert. denied,* 416 U.S. 969 (1974);[43] *Portland Cement Association* v. *Ruckelshaus,* 486 F.2d 375, 387–88 (D.C. Cir. 1973); *Sierra Club* v. *Costle,* 657 F.2d 298, 313 (D.C. Cir. 1981) (upholding standard imposing controls on sulfur dioxide (SO_2) emissions from coal-fired power plants when the ''cost of the new controls . . . is substantial'').[44] Moreover, section 111(a) does not provide specific direction regarding what metric or metrics to use in considering costs, again affording the EPA considerable discretion in choosing a means of cost consideration.[45]

b. Non-Air Quality Health and Environmental Impacts

Under CAA section 111(a)(1), the EPA is required to take into account ''any non-air quality health and environmental impact'' in determining the BSER. As the D.C. Circuit has explained, this requirement makes explicit that a system cannot be ''best'' if it does more harm than good due to cross-media environmental impacts.[46]

c. Energy Considerations

Under CAA section 111(a)(1), the EPA is required to take into account ''energy requirements.'' As discussed below, the EPA may consider energy requirements on both a source-specific basis and a sector-wide, region-wide or nationwide basis. Considered on a source-specific basis, ''energy requirements'' entail, for example, the impact, if any, of the system of emission reduction on the source's own energy needs.

d. Amount of Emissions Reductions

As the EPA has previously explained, although the definition of ''standard of performance'' does not by its terms identify the amount of emissions from the category of sources or the amount of emission reductions achieved as factors the EPA must consider in determining the ''best system of emission reduction,'' the D.C. Circuit has stated that the EPA must in fact do so. *See* 81 FR at 64529; *See Sierra Club* v. *Costle,* 657 F.2d at 326.[47]

Lignite Energy Council v. *EPA,* 198 F. 3d 930, 933 (D.C. Cir. 1999).

[33] *See Sierra Club* v. *Costle,* 657 F.2d 298, 326 (D.C. Cir. 1981).

[34] *See id.* at 347.

[35] *Essex Chem. Corp.* v. *Ruckelshaus,* 486 F.2d 427, 433 (D.C. Cir. 1973), *cert. denied,* 416 U.S. 969 (1974).

[36] *Portland Cement Ass'n,* 486 F.2d at 391 (citations omitted) (discussing the Senate and House bills and reports from which the language in CAA section 111 grew).

[37] *Id.* (citations omitted).

[38] *Lignite Energy Council* v. *EPA,* 198 F.3d 930, 933 (D.C. Cir. 1999).

[39] *Portland Cement Ass'n* v. *EPA,* 513 F.2d 506, 508 (D.C. Cir. 1975).

[40] *Sierra Club* v. *Costle,* 657 F.2d at 343 (D.C. Cir. 1981).

[41] *Id.*

[42] 1977 House Committee Report at 184.

[43] The costs for these standards were described in the rulemakings. *See* 36 FR 24876 (December 23, 1971), 37 FR 5767, 5769 (March 21, 1972).

[44] Indeed, in upholding the EPA's consideration of costs under the provisions of the Clean Water Act authorizing technology-based standards based on performance of a best technology taking costs into account, courts have also noted the substantial discretion delegated to the EPA to weigh cost considerations with other factors. *Chemical Mfr's Ass'n* v. *EPA,* 870 F.2d 177, 251 (5th Cir. 1989); *Ass'n of Iron and Steel Inst.* v. *EPA,* 526 F.2d 1027, 1054 (3d Cir. 1975); *Ass'n of Pacific Fisheries* v. *EPA,* 615 F.2d 794, 808 (9th Cir. 1980).

[45] See, *e.g., Husqvarna AB* v. *EPA,* 254 F.3d 195, 200 (D.C. Cir. 2001) (where CAA section 213 does not mandate a specific method of cost analysis, the EPA may make a reasoned choice as to how to analyze costs).

[46] *Portland Cement,* 486 F. 2d at 384; *Sierra Club,* 657 F.2d at 331; *see* also *Essex Chemical Corp.,* 486 F.2d at 439 (remanding standard to consider solid waste disposal implications of the BSER determination).

[47] *Sierra Club* v. *Costle,* 657 F.2d 298 (D.C. Cir. 1981) was governed by the 1977 CAAA version of the definition of ''standard of performance,'' which revised the phrase ''best system'' to read, ''best *technological* system.'' As noted above, the 1990 CAAA deleted ''technological,'' and thereby returned the phrase to how it read under the 1970 CAAA. The court's interpretation of this phrase in *Sierra Club* to require consideration of the amount of air emissions reductions remains valid for the phrase ''best system.''

e. Sector or Nationwide Component of the BSER Factors

The D.C. Circuit has also interpreted CAA section 111 to allow (but not require) the EPA to consider the various factors it is required to consider on a national or regional level and over time, not only on a plant-specific level or as of the time of the rulemaking.[48] [49]

3. Achievability of the Standard for Emissions

The definition of ''standard of performance'' provides that the emission limit (*i.e.,* the ''standard for emissions'') that the EPA promulgates must be ''achievable'' based on performance of the BSER. *See* 81 FR at 64539–40 (discussing D.C. Circuit case law for requirements for achievability).

4. Expanded Use and Development of Technology

The D.C. Circuit has made clear that Congress intended for CAA section 111 to create incentives for new technology, and therefore, the EPA is required to consider technological innovation as one of the factors in determining the ''best system of emission reduction.'' [50]

5. Overall Agency Discretion To Balance the Factors

The D.C. Circuit has made clear that the EPA has broad discretion in determining the appropriate standard of performance under the definition in CAA section 111(a)(1), quoted above. Specifically, in *Sierra Club,* the Court explained that ''section 111(a) explicitly instructs the EPA to balance multiple concerns when promulgating a NSPS,'' [51] and emphasized that ''[t]he text gives the EPA broad discretion to weigh different factors in setting the standard.'' [52] In *Lignite Energy Council* v. *EPA,* 198 F.3d 930 (D.C. Cir. 1999), the Court reiterated:

> Because section 111 does not set forth the weight that should be assigned to each of these factors, we have granted the agency a great degree of discretion in balancing them. . . . EPA's choice [of the 'best system'] will be sustained unless the environmental or economic costs of using the technology are exorbitant. . . . EPA [has] considerable discretion under section 111.[53]

B. Authority To Revise Existing Regulations

The EPA's ability to revisit existing regulations is well-grounded in the law. Specifically, the EPA has inherent authority to reconsider, repeal, or revise past decisions to the extent permitted by law so long as the Agency provides a reasoned explanation. *See Motor Vehicle Manufacturers Association of the United States* v. *State Farm Mutual Automobile Insurance Co.,* 463 US 29, 56–57 (1983) (''an agency changing its course must supply a reasoned analysis,'' *quoting Greater Boston Television Corp.* v. *FCC,* 143 F.2d 841, 842 (D.C. Cir.)). The CAA complements the EPA's inherent authority to reconsider prior rulemakings by providing the Agency with broad authority to prescribe regulations as necessary. *See* 42 U.S.C. 7601(a). The authority to reconsider prior decisions exists in part because the EPA's interpretations of statutes it administers ''[are not] instantly carved in stone,'' but must be evaluated ''on a continuing basis.'' *Chevron U.S.A. Inc.* v. *NRDC, Inc.,* 467 U.S. 837, 863–64 (1984). This is true, as is the case here, when review is undertaken ''in response to . . . a change in administrations.'' *National Cable & Telecommunications Ass'n* v. *Brand X Internet Services,* 545 U.S. 967, 981 (2005). Indeed, ''[a]gencies obviously have broad discretion to reconsider a regulation at any time.'' *Clean Air Council* v. *Pruitt,* 862 F.3d 1, 8–9 (D.C. Cir. 2017).

C. Authority To Regulate CO_2 From Fossil Fuel-Fired EGUs

The EPA's authority for this proposed rule is CAA section 111(b)(1). In the 2015 Rule, the EPA discussed the requirements of that provision and why the Rule met them (80 FR 64529–31). The EPA summarizes that discussion here, but is not re-opening any of the issues discussed: CAA section 111(b)(1)(A) requires the Administrator to establish a list of source categories to be regulated under section 111. A category of sources is to be included on the list ''if in [the Administrator's] judgment it causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health and welfare.'' This determination is commonly referred to as an ''endangerment finding'' and that phrase encompasses both the ''causes or contributes significantly'' component and the ''endanger public health and welfare'' component of the determination. Once the Administrator lists a source category under section 111(b)(1)(A), the Administrator then promulgates, under section 111(b)(1)(B), ''standards of performance for new sources within such that category.''

In the 2015 Rule, the EPA promulgated standards for CO_2 emissions from sources in two source categories, fossil fuel-fired electric utility steam generating units and combustion turbines. The EPA explained that because it was not listing a new source category, it was not required to make a new endangerment finding with regard to the affected sources, and the EPA added that in any event, the required endangerment finding concerned the source category, and not individual pollutants. The EPA further explained that section 111(b) does not specify what pollutants the EPA should regulate once it lists a source category, so that the EPA may exercise its discretion to regulate particular pollutants as long as the EPA provides a rational basis for doing so. In the 2015 Rule, the EPA described its rational basis for regulating CO_2 emissions from fossil fuel-fired EGUs. The EPA added that even if it were required to make an endangerment finding for those emissions in order to regulate them, the same facts that provided the rational basis would qualify as an endangerment finding.

IV. Rationale for Proposed Applicability Criteria

The current non-fossil applicability exemption is based strictly on the combustion of non-fossil fuels (*e.g.,* biomass). To be considered a non-fossil fuel-fired EGU, the EGU must be both (1) capable of combusting over 50 percent non-fossil fuel and (2) limit the use of all fossil fuels to an annual capacity factor of 10 percent or less. The current language does not take heat input from non-combustion sources (*e.g.,* solar thermal) into account. Certain solar thermal installations have natural gas backup burners that are over 250 MMBtu/h. As currently written, these solar thermal installations would not be eligible to be considered non-

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[48] *Sierra Club,* 657 F.2d at 327–28 (quoting 44 FR 33583/3–33584/1), 331 (citations omitted) (citing legislative history). *See* 81 FR at 64539; 79 FR 1430, 1466 (January 8, 2014) (explaining that although the D.C. Circuit decided *Sierra Club* before the *Chevron* case was decided in 1984, the D.C. Circuit's decision could be justified under either *Chevron* step 1 or 2. 79 FR 1430, 1466 (January 8, 2014)).

[49] The D.C. Circuit's authorization for EPA to consider the factors on a national or regional level does not refer to the types of controls or actions that may be part of the BSER, rather, it refers to the factors EPA uses to evaluate the impacts of those controls or actions.

[50] *Sierra Club,* 657 F.2d at 346–47.

[51] *Id.,* 657 F.2d at 319.

[52] *Id.,* 657 F.2d at 321; *see* also *New York* v. *Reilly,* 969 F. 2d 1147, 1150 (D.C. Cir. 1992) (because Congress did not assign the specific weight the Administrator should assign to the statutory elements, ''the Administrator is free to exercise [her] discretion'' in promulgating an NSPS).

[53] *Lignite Energy Council,* 198 F.3d at 933. *See* also *NRDC* v. *EPA,* 25 F.3d 1063, 1071 (D.C. Cir. 1994) (EPA did not err in its final balancing because ''neither RCRA nor the EPA's regulations purports to assign any particular weight to the factors listed in subsection (a)(3). That being the case, the Administrator was free to emphasize or deemphasize particular factors, constrained only by the requirements of reasoned agency decision making.'').

fossil units since they are not capable of deriving more than 50 percent of the heat input from the combustion of non-fossil fuels. Therefore, solar thermal installations that include backup burners could meet the applicability criteria of 40 CFR part 60, subpart TTTT even if the burners are limited to an annual capacity factor of 10 percent or less. Amending the applicability language to include heat input derived from non-combustion sources would allow these facilities to avoid applicability with 40 CFR part 60, subpart TTTT by limiting the use of the natural gas burners to less than 10 percent of the capacity factor of the backup burners. These EGUs would readily comply with the emissions standard, but the reporting and recordkeeping would increase costs for these EGUs. The proposed amended non-fossil applicability language of changing ''combusting'' to ''deriving'' will assure that 40 CFR part 60, subpart TTTT continues to cover the fossil fuel-fired EGUs, properly understood, that it was intended to cover, while minimizing unnecessary costs to EGUs fueled primarily by renewable energy. The corresponding change in the base load rating to include the heat input from non-combustion sources is necessary to determine the relative heat input from fossil and non-fossil sources.

The definition of design efficiency (*i.e.,* the efficiency of converting thermal energy to useful energy output) is used to determine if an EGU meets the electric sales criteria and is relevant to both new and existing EGUs. EGUs that sell less electricity than the electric sales criteria are not included in the applicability of subpart TTTT. The sales criteria is based in part of the individual EGU design efficiency. The current definition includes several specific options for determining the design efficiency. Since the 2015 final rule, the EPA has become aware that owners/operators of certain existing units do not have records of the original design efficiency. These units are therefore not able to readily determine if they meet the applicability criteria and are subject to the existing source 111(d) requirements. Many of these units are CHP units and it is highly likely they do not meet the applicability criteria. However, the current language would require them to conduct additional testing to demonstrate this. To minimize the compliance burden and to provide additional flexibility to the regulated community, the proposed amendment to the definition of design efficiency would allow the Administrator to approve alternate test methods to determine the design efficiency. For existing CHP units with large useful thermal outputs that would clearly not meet the electric sales applicability criteria, this could potentially include the use of historical operating data.

For CHP units, the current approach for determining net electric sales for applicability purposes allows the owner/operator to subtract the purchased power of the thermal host facility. The intent of the approach is to determine applicability similarly for third-party developers and CHP units owned by the thermal host facility.[54] However, as currently written, each third-party CHP unit would subtract the entire electricity use of the thermal host facility when determining its net electric sales. It is clearly not the intent of the provision to allow multiple third-party developers that serve the same thermal host to all subtract the purchased power of the thermal host facility when determining net electric sales. This would result in counting the purchased power multiple times. In addition, it is not the intent of the provision to allow a CHP developer to provide a trivial amount of useful thermal output to multiple thermal hosts and then subtract all of the thermal hosts' purchased power when determining net electric sales for applicability purposes. The proposed amendment would set a limit to the amount of thermal host purchased power that a third-party CHP developer can subtract for electric sales when determining net electric sales equivalent to the percentage of useful thermal output provided to the host facility by the specific CHP unit. This approach would eliminate both circumvention of the intended applicability by sales of trivial amounts of useful thermal output and double counting of thermal host-purchased power.

Finally, during the 2015 rulemaking, the EPA identified the Washington County (GA) and Holcomb (KS) EGU projects as ''projects under development'' that would not be able to meet the standard of performance without a complete redesign (80 FR 64542–43). As a result, the EPA determined that it would not be appropriate to apply the standard to those projects and excluded them. The EPA added that if it received information suggesting that either will be built, the Agency would propose a standard of performance specifically for the project. It is not clear if these projects will be constructed, and, if so, whether they would be able to meet the standard proposed in this action. For this reason, the EPA is not proposing to amend the manner in which the 2015 Rule addressed these projects. Thus, the proposed standard would not apply to these projects, and if the Agency receives information suggesting that either will be built, the EPA will propose a standard of performance specifically for the project. However, the EPA also requests comment on whether the projects should be covered by the standard proposed in this action (Comment C–5)

V. Rationale for Proposed Emission Standards for New and Reconstructed Fossil Fuel-Fired Steam Generating Units

In the 2015 Rule, the EPA determined that partial CCS was the BSER for newly constructed coal-fired steam generating units. The EPA determined that partial CCS had reasonable costs (the levelized cost of electricity (LCOE) was comparable to the costs of two then-current projects to add nuclear capacity, and the percentage increase in capital costs was comparable to increases that the industry had shown it could absorb),[55] was technically feasible in the majority of the U.S., achieved meaningful emission reductions, and promoted technology development. For the reasons discussed immediately below, on the basis of updated information, the EPA proposes that partial CCS does not qualify as the BSER; and for the reasons discussed further below, the EPA proposes that highly efficient generation technology is the BSER.

A. Review of the 2015 BSER Analysis

1. Review of Reasonable Cost Criteria

In the 2015 Rule, as part of the partial CCS BSER determination, the EPA evaluated the costs for new base load electricity generating options to determine what was a ''reasonable'' cost. Specifically, the EPA determined that the LCOE for a new non-natural gas fossil fuel-fired power plant would be ''reasonable'' if it was consistent with the LCOE associated with the construction of a new nuclear power plant. The EPA argued that the

[54] For contractual reasons, many developers of CHP units sell all the generated electricity to the electricity distribution grid even though in actuality a significant portion of the generated electricity is used onsite. Owners/operators of both the CHP unit and thermal host can subtract the site purchased power when determining net electric sales. Third party developers that do not own the thermal host can also subtract the purchased power of the thermal host when determining net electric sales for applicability purposes.

[55] The two projects are SCE&G and Santee Cooper's V.C. Summer Nuclear Generating Station and Georgia Power and Southern Company's Vogtle Electric Generating Station.

increased costs (relative to a newly constructed natural gas combined cycle EGU) were reasonable because utilities had indicated to the EPA that they valued the fuel diversity provided by coal-fired EGUs (80 FR 64510). The EPA also determined that an increase in the capital cost of slightly more than 20 percent was reasonable when compared to previous CAA rulemakings affecting the power sector (80 FR 64560). Since 2015, additional facts have come to light that have led the EPA to reassess these determinations and therefore to reassess the reasonableness of the cost of partial CCS.

Projections in 2015 from the EPA, EIA, and utility planners consistently showed NGCC as the lowest cost option for new intermediate and base load generation. Consistent with the 2015 Rule, current utility forecast models continue to project that few, if any, new coal-fired power plants will be built in the U.S. in the subsequent decade.[56] However, these models do not necessarily account for certain source-specific considerations that power plant developers use to determine what type of generation technology to construct. The EPA explained in the 2015 Rule that it was possible that circumstances would arise under which a developer would find it advantageous to build a new coal-fired EGU, for example, for purposes of fuel diversification (80 FR 64513), and the EPA has not received information since the 2015 Rule that would cause it to rule out that possibility. In the event a new coal-fired EGU is constructed in the U.S., in the absence of the requirements of 40 CFR part 60, subpart TTTT, as finalized in 2015, the EPA believes that the majority of large coal-fired EGUs would adopt the use of supercritical steam conditions and the majority of small coal-fired EGUs would use the best available subcritical steam conditions. This is consistent with the analysis included in the 2015 final rule.

In addition, as part of the 2015 rulemaking the EPA received public comments stating that there is value in maintaining the ability to develop non-natural gas-fired base load generation that is not captured in economic dispatch models (80 FR 64559). These values can include, but are not limited to: Historically stable fuel prices; fuel security (*i.e.,* the ability to store significant quantities of fuel onsite), and site-specific jobs and economic development considerations (*e.g.,* local mining and power plant jobs, maintaining an active rail line, maintaining the property tax base, and, in the case of coal refuse, remediation of existing environmental concerns). The EPA also noted that a number of integrated resource plans (IRPs)[57] recognize significant value in these fuel diversity considerations (80 FR 64526, 64563). Several utilities included nuclear and coal-fired options in their resource plans expressly to preserve fuel diversity within their portfolios.[58] These utility sector plans justified ''prudent'' costs (that were significantly higher than the projected least cost option) to maintain fuel diversity. Based on these factors, in the 2015 rulemaking, the EPA developed metrics for determining reasonable costs, *i.e.,* a cost level for performance standards at which new coal-fired EGUs can still be part of the future fuel diversity mix. These cost indicators were (1) the LCOE of other options for new non-natural gas-fired base load generation (*e.g.,* nuclear) and (2) the percentage increase in capital cost.

a. Levelized Cost of Electricity (LCOE) Comparison

(1) Background

As part of the 2015 rulemaking, the EPA assumed that developers valued fuel diversity and were therefore willing to pay a premium for non-natural gas-fired dispatchable base load generation. The EPA concluded that the LCOE of new nuclear (and biomass) generation was one appropriate indicator of the value of maintaining the option to develop new non-natural gas-fired base load generation. For this metric, the EPA used cost data from EIA[59] and U.S. Department of Energy National Energy Technology Laboratory (DOE/NETL)[60] to project the cost at which a new coal-fired EGU with partial CCS would have substantially similar levelized cost compared to new nuclear capacity. Table 4 includes the summary table of the EPA's cost projections from the preamble to the 2015 final rule (*See* 80 FR 64562, Table 8). The data in Table 4 reflect the EPA's 2015 determination that the cost of full carbon capture was not reasonable.[61] However, the EPA further determined that the cost of the specified partial CCS level in Table 4 was reasonable because they were comparable to the costs of new nuclear capacity. The increase in the LCOE from a supercritical pulverized coal unit due to partial CCS ranged from approximately 20 to 30 percent.

TABLE 4—PREDICTED COST AND CO_2 EMISSION LEVELS FOR A RANGE OF POTENTIAL NEW GENERATION TECHNOLOGIES FROM THE 2015 RULE

Technology	Emissions (lb CO_2/MWh-gross)	LCOE* ($/MWh)
SCPC—no CCS (bit)	1,620	76–95
SCPC—no CCS (low rank)	1,740	75–94
SCPC + ~16% CCS (bit)	1,400	92–117
SCPC + ~ 25% CCS (low rank)	1,400	95–121
Nuclear (EIA)	0	87–115
Nuclear (Lazard)	0	92–132
Biomass (EIA)		94–113

[56] Power sector modeling does not predict the construction of any new coal-fired EGUs. Therefore, based on modeled impacts, any GHG requirements for new coal-fired EGUs would have no significant costs or benefits.

[57] An Integrated Resource Plan (IRP) is a publicly available long-term resource plan outlining a utility's resource needs, considering both supply and demand side resources, to meet future energy demands reliably and cost effectively.

[58] U.S. EPA, *Technical Support Document: Review of Electric Utility Integrated Resource Plans,* July 31, 2015, available in the rulemaking docket at *https://www.regulations.gov/document?D=EPA-HQ-OAR-2013-0495-11775.*

[59] EIA, *Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2015. June 2015.* Available at *https://www.eia.gov/outlooks/archive/aeo15/pdf/electricity_generation.pdf.*

[60] U.S. DOE NETL, *Cost and Performance Baseline for Fossil Energy Plants Supplement: Sensitivity to CO_2 Capture Rate in Coal-Fired Plants,* DOE/NETL–2015/1720, June 22, 2015, available at *https://www.netl.doe.gov/energy-analyses/temp/SupplementSensitivity toCO2CaptureRateinCoalFiredPowerPlants_062215.pdf.*

[61] A further indication of the unfavorable economics of full capture CCS may be found in the recent cancellation by the Canadian firm, SaskPower of its planned CCS retrofits at additional units at the Boundary Dam facility, in Saskatchewan, Canada, due to high costs. *See* C. Marshall, ''Landmark project puts coal expansion on ice,'' *Greenwire,* July 10, 2016 (subscription required).

TABLE 4—PREDICTED COST AND CO_2 EMISSION LEVELS FOR A RANGE OF POTENTIAL NEW GENERATION TECHNOLOGIES FROM THE 2015 RULE—Continued

Technology	Emissions (lb CO_2/MWh-gross)	LCOE* ($/MWh)
Biomass (Lazard)		87–116
IGCC	1,430	94–120
NGCC	1,000	** 52–86

* The emissions and LCOE (2011 $) for the SCPC cases, IGCC, and NGCC are based on the NETL ''Sensitivity to CO_2 Capture Rate'' report. The nuclear and biomass LCOE (2011 $) are based on data from EIA and Lazard. The LCOE ranges include an uncertainty of −15%/+30% on capital costs for SCPC and IGCC cases and an uncertainty of −10%/+30% on capital costs for nuclear and biomass cases. LCOE estimates displayed in this table for SCPC units with partial CCS as well as for IGCC units use a higher financing cost rate in comparison to the SCPC unit without capture.

** This range represents a natural gas price from $5/MMBtu to $10/MMBtu.

(2) Comparison With Biomass-Fired Power Plants

While the EPA included biomass in the 2015 rulemaking LCOE analysis, the EPA noted that new nuclear power, which, besides natural gas combustion turbines, is the principal other option often considered for providing new base load power (79 FR 1477). Biomass-fired EGUs are smaller in scale [62] and not as closely analogous to coal-fired generation as is nuclear power. EIA projects that average net additional biomass generation capacity amounts to less than 100 MW annually. The largest domestic biomass-fired EGU is less than 200 MW and the largest international biomass-fired EGUs are less than 300 MW. Similar to coal refuse-fired EGUs, biomass-fired EGUs are limited geographically because they tend to be located in areas with large quantities of biomass that can be cost effectively delivered to the plant. Based on these considerations, the EPA does not consider biomass to be an appropriate comparison for coal-fired generation.

(3) Comparison With Nuclear-Fueled Power Plants

(a) Levelized Cost of Electricity (LCOE)

In the 2015 analysis, the EPA assumed nuclear generation and coal-fired generation were similarly attractive for purposes of fuel diversity. As part of this review, the EPA is reevaluating whether that assumption is valid. Specifically, the EPA is requesting comment on whether nuclear capacity is more attractive than coal as an option for providing fuel diversity (Comment C–6). Nuclear projects have no emissions of criteria pollutants, hazardous air pollutants (HAPs),[63] or GHGs. Particularly in light of potential future costs associated with GHG emissions, nuclear projects provide a significant price stability guarantee. In addition, the incremental generating costs for nuclear projects are lower than those for coal-fired EGUs, thus, nuclear EGUs would be expected to dispatch more frequently and provide more actual non-natural gas generation per amount of installed capacity.[64] Therefore, to the extent that nuclear projects are more attractive than coal-fired EGUs for providing fuel diversity, developers could be willing to pay more of a premium for nuclear projects than for coal-fired EGUs.

On the other hand, more recent information, since the 2015 Rule, indicates that the LCOE of a new nuclear EGU is in fact higher than what developers may be willing to accept. In 2015, multiple new advanced Generation III+ nuclear units were under construction in the U.S.[65 66] including, at that time, two new units each at the Summer and Vogtle nuclear power plants in South Carolina and Georgia, respectively. However, since the 2015 Rule, both the Summer and Vogtle projects have experienced significant delays and cost overruns. South Carolina Electric and Gas (SCE&G), majority owner of Summer, has now abandoned completion of both reactors and has raised rates at least nine times to cover the increasing costs of the reactors.[67] While over budget and behind schedule, construction of both the Vogtle units continues. They are scheduled to be completed in 2021 and 2022. Furthermore, there appear to be no new nuclear projects under construction or that have received regulatory approval at this time. According to EIA, which reports data on recently constructed EGUs and planned EGU additions, including EGUs under construction, EGUs that have received regulatory approvals but that have not commenced construction, and planned projects that have not received regulatory approvals, the only planned nuclear project is the Utah Associated Municipal Power Systems (UAMPS) Carbon Free Power Project. This project proposes to use small modular nuclear reactors developed with funding from the DOE. However, this project has not yet received all of the required regulatory approvals to proceed. The EPA solicits comment on the extent to which new nuclear energy projects can serve as a comparison point, for purposes of fuel diversity, for new coal-fired EGUs (Comment C–7).

In the 2015 Rule, the partial CCS costs were based largely on the report, ''Cost and Performance Baseline for Fossil Energy Plants Supplement: Sensitivity to CO_2 Capture Rate in Coal-Fired Power Plants,'' June 22, 2015 (DOE/NETL–2015/1720). The EPA used the reported costs without any significant adjustments. In this rulemaking, the EPA is proposing to make refinements to the CO_2 transmission and storage (T&S) costs and EGU capacity factors. That is, as described below, the EPA is proposing to adjust the T&S costs based on the amount of CO_2 captured and adjust the capacity factor based on the increase in variable operating costs due to the impact of partial CCS. Accounting for these factors revises the LCOE with partial CCS upwards. The EPA also proposes in the alternative to use the NETL costs without any significant adjustments, similar to the approach used in the 2015 Rule. The EPA is not aware of any more recent, detailed, or transparent costing analysis specific to coal-fired EGUs with or without carbon capture technology. The EPA invites the

[62] Biomass-fired EGUs tend to have challenges in securing and transporting large amounts of biomass.

[63] HAP are toxic air pollutants regulated under CAA section 112.

[64] EIA used a 90 percent capacity factor for nuclear when calculating the LCOE in the 2015 Rule. According to EIA, the average nuclear EGU capacity factors was 92 percent in 2017.

[65] EIA, *Form EIA–860 Detailed Data,* 2014, available at *https://www.eia.gov/electricity/data/eia860/,3_1_Generator_Y2014.xls,* ''Proposed'' sheet.

[66] As of the promulgation of the 2015 Rule, 4,400 MW of new nuclear capacity was under construction with 2019–20 commercial operating dates.

[67] G. Blade, ''Santee Cooper, SCANA abandon Summer nuclear plant construction,'' *Utility Dive,* July 31, 2017, available at *https://www.utilitydive.com/news/santee-cooper-scana-abandon-summer-nuclear-plant-construction/448262/.*

public to identify any additional costing information.

First, the CO_2 T&S costs in the NETL baseline reports are not included in the reported capital cost or operation and maintenance (O&M) costs but are treated separately and added to the LCOE. Specifically, the combined transport and storage costs for geologic storage (not accounting for any revenues from the sale of CO_2) equaled $11 per metric ton of captured CO_2. This cost represents annual transportation through a 100-kilometer (km) (62 mile) CO_2 pipeline and storage in a deep saline formation in the Midwest of 3.2 million tons of CO_2.[68] The EPA used this value in all the partial capture cases as well. In this rule, to account for economies of scale, the EPA is proposing to adjust the T&S costs based on the amount of CO_2 captured. To estimate the T&S costs, the EPA is using the FE/NETL CO_2 Transport Cost Model and the FE/NETL CO_2 Saline Storage Cost Model with the same general assumptions described in ''Performance Baseline for Fossil Energy Plants, Volume 1a: Bituminous Coal (PC) and Natural Gas to Electricity, Revision 3,'' July 6, 2015 (DOE/NETL–2015/1723) and adjusting the metric megatons of CO_2 transported and stored.[69] Table 5 shows the resulting total estimated T&S costs for various amounts of captured CO_2.

TABLE 5—CO_2 TRANSPORT AND STORAGE COSTS FOR VARIOUS AMOUNTS OF CAPTURE

Megatonne (Mt)/yr	Total T&S cost (2016 $/tonne)
4.2	9.6
3.2	11
2.6	12
2.0	13
1.4	16
0.62	29

The EPA is using the best fit trendline to estimate the T&S costs for various amounts of CO_2 capture. The trendline predicts that costs would increase substantially at lower levels of capture. As stated previously, the EPA also proposes in the alternative to use an $11 metric ton T&S costs consistent with the NETL costing approach and the 2015 Rule.

Second, as part of the 2015 rulemaking, for the LCOE calculations, consistent with the NETL calculations, as noted above, the EPA assumed a constant capacity factor[70] (*i.e.,* electric sales) regardless of the amount of CCS installed on the representative (*i.e.,* model) coal-fired EGU. This simplified approach captured the fixed and operating costs of CCS but did not account for the impact of economic dispatch (*e.g.,* it did not include analysis of the interaction of the affected EGU with the grid or other EGUs on an hourly basis) and loss of potential revenue due to lower electric sales.

However, electricity is a unique commodity in that it cannot (at present) be stored at a large scale at a reasonable cost. Therefore, electric grid operators need to make plans and take actions to match supply and demand in real time. Multiple factors influence which EGUs supply power to the grid to satisfy system load (*e.g.,* transmission and operational constraints) at any given point, and in which order. In the simplest terms, economic dispatch is used to satisfy the grid load at minimal costs. In the economic dispatch model, EGUs with the lowest marginal (*i.e.,* operating) costs are dispatched first. Those EGUs increase output until all the load is satisfied or until the EGUs cannot supply additional power. If needed, EGUs with higher operating costs are then dispatched to satisfy demand. The process continues by dispatching more expensive units until the grid load is satisfied. The marginal cost of the final generator needed to meet load sets the system marginal cost. Owners and operators of generators are paid based on the system marginal cost. Therefore, net revenue is the difference between the variable operating costs and the system marginal cost.

Importantly, economic dispatch only accounts for the costs directly associated with power plant operations and does not consider any fixed costs. This is important because historically units with high fixed costs (*e.g.,* coal-fired and nuclear EGUs) have low operating costs, dispatch often, and typically run as base load units. For example, nuclear units tend to have operating costs on the order of $15 to $20 per MWh and capacity factors of greater than 90 percent. These units would be able to recover their high fixed costs by spreading them out over many MWh of electric sales. Units with low fixed costs but high operating costs (*e.g.,* simple cycle combustion turbines) have historically tended to dispatch last and provide peaking power. With natural gas prices of $4 per MMBtu, the operating costs of simple cycle units are approximately $40 per MWh and capacity factors are less than 10 percent in most cases. Therefore, an increase in operating costs of $20 per MWh can change an EGU from a high capacity factor base load unit to a peaking unit with limited operation. Emission control equipment can impact both the fixed costs and operating costs of an EGU. Another important aspect of economic dispatch, which may be unique to the electricity generation sector, is that the end user (*i.e.,* consumer) has historically had limited, if any, choice in what technology is used to generate electricity. Therefore, electric generators compete strictly on the basis of their variable costs, with no ability to differentiate their product.

In deregulated markets, a new coal-fired EGU must compete directly against all other forms of generation, including existing coal-fired EGUs and natural gas-fired combined cycle units. A developer of a new coal-fired EGU could anticipate revenues from capacity payments, various ancillary services, and to the extent the new unit is dispatched, energy payments. In a deregulated market, each of these revenue streams is priced through competitive market-based structures. As described earlier, revenue from energy payments will largely be determined based on variable operating costs. Any requirements that impact variable operating costs could impact the ability of the owner/operator of a new coal-fired EGU to obtain adequate revenues to cover the generation investment and recover costs.

In the 2015 Rule, commenters indicated that competitive electricity markets only allow for the entry of competitively-priced power. Therefore, a new coal plant with partial CCS that was compliant with an NSPS requirement based on the use of CCS might not be competitive compared to older coal plants with no CCS requirements (even if the older plants are less thermally efficient). The EPA responded that, given current and projected market conditions, any new coal-fired EGU would likely only be built in a location where it would be expected to operate at a high capacity factor (*e.g.,* as a base load unit). However, at least in deregulated markets, economic dispatch is still a factor for base load units and can change annual capacity factors by multiple percentage points. Moreover,

[68] Use of the T&S costs for the Illinois Basin (*i.e.,* Midwest) are consistent with the NETL costing approach. According to NETL, T&S costs would be similar for the East Texas Basin. However, T&S costs for the Williston Basin are estimated to be 40 percent higher, and T&S costs for the Power River Basin are approximately double.

[69] For additional detail on CO_2 T&S costing see section 2.7.3 CO_2 Transport and Storage in volume 1a, revision 3 of the NETL baseline reports and the T&S technical support document that is available in the docket.

[70] EPA used an 85 percent capacity factor, consistent with the NETL LCOE calculations.

an increasing number of coal-fired power plants are changing from base load to variable load. Accordingly, the EPA is proposing to include the impact of economic dispatch in determining the costs of a potential new coal-fired EGU. Inclusion of these costs is a more refined representation of the impact of the BSER determination. As stated previously, the EPA is proposing in the alternative that the Agency not account for economic dispatch and instead use the same capacity factors regardless of variable operating costs, for the same reasons as the EPA stated in the 2015 Rule.[71]

To estimate the impacts at a national level of the increase in variable operating costs due to partial CCS, the EPA analyzed the dispatch of coal-fired EGUs relative to variable operating costs.[72] Based on a review of the variable operating costs and capacity factors in the Annual Energy Outlook 2018 and fuel prices reported under EIA form 923, the EPA determined that capacity factors for coal-fired EGUs decrease approximately 1.5 percent for each $1/MWh increase in operating costs. Table 6 shows the operating costs of various generating technologies. The capacity factors for coal-fired EGUs have been adjusted based on a baseline of the relevant coal rank supercritical EGU having a capacity factor of 85 percent.

TABLE 6—PROPOSED T&S COSTS AND CAPACITY FACTORS *

Technology	Captured CO_2 (Mt)	T&S costs ($/tonne)	Variable operating costs ($/MWh)	Amended CF (percent)
Subcritical PC (bit)			32.3	83.5
Supercritical PC (bit)			31.3	85.0
SCPC + ~16% CCS (bit)	520,000	30	36.9	76.6
Supercritical PC (low rank)			28.0	85.0
Ultra-supercritical PC (low rank)			27.4	85.8
SCPC + ~ 26% CCS (low rank)	1,000,000	20	36.3	72.5
Combined Cycle CT (NG)			33.1	
Simple Cycle CT (NG)			50.7	

* Variable operating costs calculated using $2.61/MMBtu for bituminous coal, $2.09/MMBtu for low rank coal, and $4.73/MMBtu for natural gas. Captured CO_2 based on an 85 percent capacity factor. Costs are in 2016 $. Variable operating costs is also referred to as incremental generating costs. Simple cycle CT variable operating costs were estimated by adjusting the combined cycle efficiency to 33 percent.

The variable operating costs shown in Table 6 demonstrate part of the reason why the U.S. generation mix is changing so dramatically with the decrease in the price of natural gas. Fuel costs comprise approximately two thirds to three quarters, depending on the coal type, of the variable operating costs for coal-fired EGUs. In comparison, fuel costs comprise over 90 percent of the variable operating costs for combined cycle EGUs. Therefore, declining natural gas prices can have a dramatic impact on the competitiveness of natural gas-fired EGUs relative to coal-fired EGUs. While the variable operating costs in Table 6 are based on long term projections for the price of natural gas, spot process can be significantly lower. When natural gas is available at $4/MMBtu or less, the variable operating costs of combined cycle units can drop below those of certain coal-fired EGUs and displace those units in the dispatch order. The data further show that due to the relatively high operating costs of CCS compared to other environmental controls,[73] a BSER based on partial CCS increases the variable operating costs of new coal plants to significantly greater than existing coal-fired EGUs without GHG controls. Therefore, in an economic dispatch system, a new coal-fired EGU with partial CCS would dispatch after the majority of existing coal-fired EGUs.[74] In markets with significant quantities of coal-fired generation, this could have a significant impact on the economic viability of a new coal-fired EGU. Table 7 shows the LCOE at an 85 percent capacity factor and $11/tonne T&S costs compared to an LCOE using the amended T&S costs (based on the amount of CO_2 captured) and using an adjusted capacity factor (based on the variable operating costs). The revised LCOE numbers account for both the amended approach to calculating T&S costs and the change in capacity factor.

TABLE 7—PREDICTED COST AND CO_2 EMISSION LEVELS FOR A RANGE OF POTENTIAL NEW GENERATION TECHNOLOGIES

Technology	LCOE * ($/MWh)	Amended LCOE ** ($/MWh)
Subcritical PC (bit)	81.2	82.1
Supercritical PC (bit)	81.7	81.7
SCPC + ~16% CCS (bit)	96.2	105.4
Supercritical PC (low rank)	85.2	85.2
Ultra-supercritical PC (low rank)	87.6	87.0

[71] One approach developers could take to reduce the impact on the capacity factor could be to construct a smaller EGU. While this would not impact capacity factors strictly based on simplified economic dispatch (*i.e.,* at the same variable operating costs the unit would still dispatch after units with lower variable operating costs) multiple factors impact dispatch and a smaller unit might provide local grid support that would allow it to operate at higher capacity factors.

[72] Fuel costs comprise approximately two-thirds to three-fourths of the variable operating costs for a coal-fired EGU.

[73] The EPA notes that unlike other environmental controls, there is limited regulatory requirements or incentive to reduce GHG emissions aside from the NSPS requirements. For example, local or regional programs could require reductions in criteria pollutant from all EGUs and/or owners/operators of EGUs can accrue regulatory benefits in other regulatory programs due to criteria pollutant reductions (*e.g.,* offsets and emission credits). These programs minimize the impact of the environmental controls on dispatch because costs are spread more evenly to the entire EGU fleet.

[74] This could create a perverse environmental incentive to operate existing coal more than it otherwise would. A utility-system dispatch model would be required to estimate the potential overall environmental impacts.

TABLE 7—PREDICTED COST AND CO_2 EMISSION LEVELS FOR A RANGE OF POTENTIAL NEW GENERATION TECHNOLOGIES—Continued

Technology	LCOE * ($/MWh)	Amended LCOE ** ($/MWh)
SCPC + ~ 26% CCS (low rank)	109.0	122.8

* 85 percent capacity factor and $11/tonne T&S.
** Capacity factor adjusted based on variable operating costs and T&S costs adjusted based on amount of captured CO_2.

Assuming a constant 85 percent capacity factor and $11/tonne T&S costs, the LCOE for a bituminous-fired SCPC with partial CCS is 18 percent higher than a SCPC without CCS. However, when the refined T&S and capacity factors are accounted for, the relative increase in LCOE for a bituminous-fired SCPC with partial CCS is 29 percent higher than SCPC without CCS, a 63 percent increase in the relative LCOE impact of partial CCS. These costs do not account for any of the potential benefits of reduced criteria and GHG emissions due to the use of partial CCS. The EPA solicits comment on if these should be factored into the analysis, and if so, appropriate metrics to accounting for these benefits (Comment C–8). Furthermore, the revised LCOE costs are over 10 percent higher than the nuclear cost metric. Furthermore, even with only the T&S adjustment, the revised LCOE are five percent higher than the nuclear metric. The results of this analysis support the EPA's proposal to revise the 2015 determination that partial CCS is BSER for coal-fired EGUs. The EPA notes that these costs are for coal-fired EGUs that are using geologic sequestration (GS) and do not account for any specific economic incentives (*e.g.,* the federal tax credits for carbon capture, which are available only for new facilities that commence construction before January 1, 2024, Internal Revenue Code §§ 45Q(a)(3)-(4), (d)—which, in turn, is before the end of the 8-year period in which the EPA is required to review and, if necessary, revise the standard of performance that is the subject of this rulemaking, CAA section 111(b)(1)(B)). If the owner/operator were in a location where it could sell the byproduct CO_2 (*e.g.,* for enhanced oil recovery or for use in the food industry) variable operating costs could be reduced relative to an EGU without partial CCS and electric sales would be expected to increase, offsetting some of the control costs. For example, as discussed in the 2015 Rule, two coal-fired EGUs elected to install carbon capture technology and sold the CO_2 to the food industry without any federal funding for the capture technology (80 FR 64550). This type of utilization of CO_2 has the potential to both develop capture technologies and increase economic options to reduce emissions. While sale of the captured CO_2 improves the overall economics of a new coal-fired EGUs, the EPA recognizes that there are places where opportunities to sell captured CO_2 for utilization may not be presently available. Therefore, consistent with approach adopted in the 2015 Rule, the EPA is assuming no revenues from the sale of captured CO_2 (80 FR 64572).

(b) Consideration of Capital Cost Increases

In the 2015 rulemaking, commenters from industry recommended that the EPA should separately consider the significant capital costs of partial CCS. In response to these comments, the EPA evaluated the impact of 2015 GHG standards on the capital costs of new fossil-steam generation and compared the same to the capital costs of prior EPA regulations. The EPA determined that the incremental capital costs of partial CCS were reasonable because they were comparable to the percentage capital costs increase in prior regulations and because the utility industry has demonstrated the capacity to successfully absorb capital costs of this magnitude in the past (80 FR 64559). Specifically, in the 2015 final rule, the EPA concluded that an increase of 21 to 22 percent for capital coats was reasonable (80 FR 64560).

The EPA cited several comparable rulemakings. First, the 1971 NSPS for coal-fired EGUs increased costs by $19 million (M) for a 600 MW plant. These costs consisted of $3.6 M for particulate matter (PM) controls, $14.4 M for SO_2 controls, and $1 M for nitrogen oxide ($NO_X$) controls; the capital cost of air pollution control devices added 15.8 percent to the $120 M capital cost of a new EGU. In that case, the baseline cost was primarily for a coal-fired EGU with limited environmental controls. In addition, a retrospective Congressional Budget Office (CBO) study of the 1978 EGU NSPS amendments estimated that those amendments increased the capital costs for a new EGU by 10 to 20 percent. There, the baseline costs and overall absolute costs were higher than the 1971 NSPS because they included the cost of controls required by the 1971 NSPS. Since the 1978 NSPS, additional environmental controls have further increased the baseline costs to construct a new coal-fired EGU. These additional costs include, but are not limited to, NSPS amendments that established selective catalytic reduction (SCR) as the BSER for NO_X controls in place of low NO_X combustion controls and more stringent SO_2 and PM standards, rulemakings that require mercury (Hg) controls, and rulemakings that limit the use of once-through cooling. All of these additional environmental control requirements increase the baseline costs of constructing a new coal-fired EGU. Therefore, at the same percentage increase in capital costs, absolute costs are much higher. A comparable analysis would require that the additional control costs due to previous rulemakings be accounted for in the baseline costs when determining an appropriate percent increase in capital costs. The EPA notes that even without accounting for the different cost basis, the absolute increase in capital costs was higher for the 2015 Rule than previous EGU NSPS rulemakings. It should also be noted that the previous NSPS rulemakings generally concerned multiple pollutants and adopted multiple requirements based on multiple control technologies, which makes it more challenging to compare them with the current rulemaking, which in turn concerns, as a practical matter, a single air pollutant—CO_2—and a single set of controls.

Furthermore, the fact that the utility industry was able to absorb 20 percent increases in cost due to pollution control in the past does not necessarily mean the industry could do so today. For example, when previous NSPS rulemakings with significant costs for new coal-fired EGUs were completed, electricity demand was growing and few alternatives existed for intermediate and base load generation. At that time, a new coal-fired EGU built by a regulated utility could anticipate operating at a high capacity factor for several decades.

The utility sector is markedly different today. Currently, many coal-fired EGUs operate at variable load and it would be more difficult for an owner/operator of a new coal-fired EGU to recoup the additional control costs. Based on these assessments, the EPA is proposing that the increase in capital costs due to partial CCS are not reasonable.

In addition, in the 2015 Rule, the EPA cited the *Portland Cement Ass'n* ruling that upheld a 12 percent increase in capital costs as reasonable (*See* 80 FR 64560, citing 486 F.2d at 387–88). As stated previously, the EPA is proposing in this rule that the increase in capital costs due to partial CCS are not reasonable. In any event, *Portland Cement Ass'n* is not relevant because, as the EPA further noted in the 2015 Rule, the costs of control equipment (capital and operating) for the Portland Cement NSPS could be passed on without substantially affecting competition with construction substitutes such as steel, asphalt, and aluminum. *Id., citing Portland Cement Ass'n* v. *Ruckelshaus,* 513 F.2d 506, 508 (DC Cir. 1975). However, in the 2015 Rule, the EPA did not account for the loss of sales (*i.e.,* revenue) in the electricity market. As described previously, at least in deregulated markets, for coal-fired EGUs, an increase in operating costs has an impact on dispatch order and thus product (*i.e.,* electricity) sales, and therefore, the overall cost of the partial CCS BSER determination. That is, the ability of EGUs to pass along their capital costs to consumers depends on their ability to pass along their operating costs to consumers. However, higher operating costs that impact the EGU dispatch order cannot be passed on to end users as easily (and profit margins cannot be narrowed as easily) without affecting coal-fired generation's competitiveness with alternate forms of electricity generation. This means that EGUs cannot pass along their capital costs as easily as other industries.

(c) Other Measures of Reasonable Costs

The EPA has reviewed the rationale for a dozen GHG permits for EGUs and other industrial facilities that were permitted between 2011 and 2017. Aside from industrial sources with existing, nearly pure CO_2 process streams (*e.g.,* a natural gas processing facility) situated near an existing CO_2 pipeline (*i.e.,* a few hundred feet) that could implement CO_2 capture at little or no net cost, none of the GHG permits considered CCS to be a reasonable cost control technology. Energy efficiency was considered the appropriate control technology for the majority permit determinations. The fact that all of the EGU permit determinations rejected CCS as a reasonable control technology supports the conclusion that CCS is not an appropriate BSER.

2. Whether CCS Is Adequately Demonstrated

In the 2015 Rule, the EPA found that partial CCS was ''adequately demonstrated'' under CAA section 111(a)(1), a requirement that, as noted above, incorporates the concept of technical feasibility. However, upon further review, the EPA is proposing to revise its analysis and determine that CCS is not adequately demonstrated in certain key respects, as described in this section.

a. Availability of Geologic Sequestration (GS)

In the 2015 Rule, the EPA noted that, as a practical matter, the issue of whether all new steam-generating EGUs can implement partial CCS depends on the geographic scope of suitable GS sites. Therefore, as part of that rulemaking, the EPA performed a geographic analysis [75] in which the Agency examined areas of the country with sequestration potential in deep saline formations, oil and gas reservoirs, unmineable coal seams, and active, enhanced oil recovery (EOR) operations; information on existing and probable, planned or under study CO_2 pipelines; and areas within a 100-km (62-mile) area of locations with sequestration potential. The distance of 100 km was consistent with the assumptions underlying the NETL cost estimates for transporting CO_2 by pipeline. Based on the geographic analysis performed, the EPA determined that GS sites were widely available and that a steam-generating plant with partial CCS, sited near an area suitable for GS, could serve power demand in a large area, notwithstanding that the area itself might not contain sequestration sites. As part of the review for this action, the EPA has re-evaluated these determinations. In addition, the EPA has reviewed the impact of water availability with respect to geographic availability of CCS.

Since the 2015 Rule, the EPA has updated its analysis on geographic availability. Using updated information from NETL,[76] the Agency has identified the geographic extent of potential GS in deep saline formations and oil and gas reservoirs. The updated data show relatively minimal changes in estimated storage resources, with most of the changes occurring in Wyoming and Midwestern states (Kentucky, Michigan, Illinois, Indiana and North Dakota) as a result of additional characterization and assessment studies by the DOE Regional Carbon Sequestration Partnerships.[77] In addition, the EPA has updated its list of counties where active EOR operations are occurring, based on data reported to the EPA Greenhouse Gas Reporting Program (GHGRP) (*See* 40 CFR part 98, subpart UU, Injection of Carbon Dioxide, 2011–2017 data).[78] The GHGRP data show four additional counties where active EOR operations have occurred since the EPA's analysis in 2015. Finally, the Agency has updated its information on existing CO_2 pipelines based on Department of Transportation data along with the locations of pipelines that are probable, planned or under study. In general, these updates do not significantly change the EPA's understanding of which areas are amenable to GS.

The NETL Carbon Storage Atlas (Atlas) used for the EPA's analysis of geographic availability provides a high-level overview of prospective resources across the United States. This assessment represents the fraction of pore volume of porous and permeable sedimentary rocks available for CO_2 storage and accessible to injected CO_2 via drilled and completed wellbores. The estimates in the Atlas do not take into account economic or regulatory constraints, only physical constraints (*i.e.,* the accessible parts of geologic formations via wellbores). The deployment of partial CCS is site-specific and its application will depend on local market and geologic conditions. Therefore, the cost of deploying partial CCS will be highly variable on a geographic basis. While storage capacity appears large in the Atlas, site-specific technical, regulatory, and economic considerations will ultimately impact how much of that resource is economically available. That is, the Atlas shows an estimate of potential storage areas, but not economically

[75] U.S. EPA, *Technical Support Document: Geographic Availability,* July 31, 2015, available in the rulemaking docket at *https://www.regulations.gov/document?D=EPA-HQ-OAR-2013-0495-11772.*

[76] U.S. DOE NETL, *Carbon Storage Atlas, Fifth Edition,* September 2015, available at *https://www.netl.doe.gov/research/coal/carbon-storage/atlasv.*

[77] For deep saline formations, the low-end estimate of storage resource increased from 2,100 billion metric tons to 2,379 billion metric tons, and the high-end estimate increased from 20,014 billion metric tons to 21,633 billion metric tons. For oil and gas reservoirs, the storage resource was previously estimated at 225 billion metric tons, and is now estimated at a low-end estimate of 186 billion metric tons and a high-end estimate of 232 billion metric tons.

[78] U.S. EPA, *Greenhouse Gas Reporting Program,* available at *https://www.epa.gov/ghgreporting.* Data reported as of August 19, 2018.

viable storage areas (*i.e.,* areas where projects make business and financial sense). Additionally, the various types of geologic formations assessed in the Atlas have been characterized to varying degrees. That is, there is more uncertainty in the assessment of certain types of formations as compared to others. The maturity of oil and gas exploration and production in certain parts of the United States makes sequestration potential in these reservoirs relatively well understood. However, there are still limitations to the feasibility of GS in all oil and gas reservoirs identified as areas of potential storage in the Atlas. Additionally, despite showing large potential, saline storage has not yet been demonstrated to be available, both from a geographical perspective as well as economically, at all locations. For example, the major milestone saline project from Archer Daniels Midland is underway, but only reflects the feasibility of saline injection and storage at one location in the United States. This project is still in its early stages and has not yet proven that GS in saline formations can be done throughout the United States (at scale) in wide geographic regions with highly diverse geologic conditions. The project is sized at one million metric tons per year and may not demonstrate the full application of saline storage necessary for a large power project.

Regarding the third type of geologic formation assessed in the Atlas, unmineable coal seams, the EPA has changed its assumptions since the 2015 analysis. While the Atlas includes potential availability of unmineable coal seams, the EPA has excluded this type of formation from potential GS areas. As part of its 2015 analysis, the EPA expressed its view unmineable coal seams offered the potential for geologic storage and explained the technical process by which it thought that CO_2 could be injected underground to enhance methane recovery (also known as enhanced coalbed methane recovery) while adsorbing to the coal surface (80 FR 64576). NETL identified states that it considered had the potential for storage in unmineable coal seams. Some of these areas, including Iowa and Missouri, have little to no EOR or saline sequestration potential and generate electricity at coal-fired EGUs. Several successful small-scale demonstration projects had been performed to evaluate the potential for GS in unmineable coal seams, and research to optimize CO_2 storage in coals was ongoing. However, upon further review, the EPA now believes that the processes and technologies associated with GS at unmineable coal seams are still being developed and, in the years since the EPA expressed the understanding and expectations underlying this aspect of its analysis in the 2015 Rule, there have been no large-scale demonstrations of GS associated with unmineable coal seams.[79] In the 2015 rulemaking, the EPA had found that the largest pilot project, the Allison Unit CO_2-ECBM pilot in New Mexico, stored 270,000 metric tons of CO_2 from 1995–2001 (an average of 45,000 tons per year).[80] Recent DOE Regional Carbon Sequestration Partnership projects have injected CO_2 volumes ranging from 90 tons to 16,700 tons.[81] While these projects demonstrated some degree of potential for GS in unmineable coal seams, most were in the nature of pilot programs undertaken to evaluate project designs and collect data to better understand the mechanisms of injection and CO_2 storage. Therefore, the project durations and injected amounts were limited. The limited duration and amounts of the tests may have affected the outcomes, as some tests began to show decreases in the effectiveness of CO_2 injection over time due to swelling of the coals. This observation raises doubts regarding the feasibility of larger-scale GS in unmineable coal seams at this time. For example, in the Pump Canyon test, the effectiveness of CO_2 storage was believed to be limited due to the small amount of CO_2 injected.[82] The amount of CO_2 injected in these tests was significantly less than projects at deep saline formations or at oil and gas reservoirs where CO_2 was injected in the million-ton range. The EPA now believes that additional research using larger scale and longer duration tests in unmineable coal seams is needed to improve the understanding and modeling of CO_2 storage in coals.

[79] See, *e.g.,* M. Godec *et al.,* ''CO_2-ECBM: A Review of its Status and Global Potential,'' *Energy Procedia* 63: 5858–5869 (2014), available at *https://doi.org/10.1016/j.egypro.2014.11.619;* IEAGHG, *Potential Implications on Gas Production from Shales and Coals for Geological Storage of CO_2,* Report Number 2013/10, September 2013, available at *http://www.ieaghg.org/docs/General_Docs/Reports/2013-10.pdf.*

[80] *Id.*

[81] J. Litynski *et al.,* ''Using CO_2 for enhanced coalbed methane recovery and storage, *CBM Review,* June 2014, available at *https://www.netl.doe.gov/File%20Library/Research/Carbon-Storage/Project-Portfolio/CBM-June-2014.pdf.*

[82] M. Godec *et al.,* ''CO_2-ECBM: A Review of its Status and Global Potential,'' *Energy Procedia* 63: 5858–5869 (2014), available at *https://doi.org/10.1016/j.egypro.2014.11.619;* IEAGHG, *Potential Implications on Gas Production from Shales and Coals for Geological Storage of CO_2,* Report Number 2013/10 (September 2013), available at *http://www.ieaghg.org/docs/General_Docs/Reports/2013-10.pdf.*

Unmineable coal seams have not been shown to be a suitable GS technology option for purposes of this action; however, such formations could have potential applicability in the future. Therefore, unmineable coal seams have been excluded from potential GS areas in the analysis underlying this proposal. The elimination of unmineable coal seams reduces the geographic availability of sequestration areas by approximately 4 percent.[83]

For these reasons, GS may not be as widely geographically available as assumed in the 2015 analysis. Further work being conducted by DOE to devise and develop technologies that can improve wellbore integrity, increase reservoir storage efficiency, quantitatively assess and mitigate risks, and confirm permanent storage of CO_2 through reliable, cost-effective, multilevel monitoring programs in storage complexes in diverse geologic settings would help determine actual availability of GS in all types of formations. Additionally, work on the DOE Carbon Storage Assurance Facility Enterprise (CarbonSAFE) initiative, an effort to develop an integrated CCS storage complex constructed and permitted for operation in the 2025 timeframe, will increase understanding of the feasibility of GS across the United States and further characterize the availability of GS.

b. Water Availability

Currently available amine-based solvent capture systems require water for process makeup and cooling. As part of the 2015 rulemaking, multiple commenters expressed concerns that the EPA's determination that partial CCS was BSER was inappropriate because of increased water consumption impacts and geographical (or other) water availability/scarcity issues limiting or eliminating CCS implementation. The EPA acknowledged that, similar to other air pollution controls, such as a wet flue gas desulfurization scrubber, post-combustion amine-based capture systems result in increased water consumption. However, the EPA evaluated the issue and found the water use to be manageable (80 FR 64593). The Agency stated that the studies[84]

[83] Based on an analysis of the information provided in U.S. DOE NETL, *Carbon Storage Atlas, Fifth Edition,* September 2015, available at *https://www.netl.doe.gov/research/coal/carbon-storage/atlasv* and areas within 100 km (62 miles) of these locations. The geographic area decreased by 411,156 square km (158,748 square miles).

[84] *See* comments of UARG at p. 84 (Docket entry: EPA–HQ–OAR–2013–0495–9666) citing Haibo Zhai, *et al.,* ''Water Use at Pulverized Coal Power Plants with Post-Combustion Carbon Capture and Storage,'' *Environ. Sci. Technol.,* 45:2479–85 (2011);

referenced by commenters that indicated significant increases in water use from CCS cooling and process operations compared to coal-fired EGUs without CCS were for cases where full CCS (90 percent or greater capture) is implemented, and were therefore of limited relevance to its determination that *partial* CCS was BSER.

In the 2015 Rule, the EPA examined water use predicted from the updated DOE/NETL studies to determine the magnitude of increased water usage for a new SCPC EGU implementing partial CCS to meet the final standard of 1,400 lb CO_2/MWh-gross. The EPA in 2015 determined that the results showed that a new SCPC unit that implements 16 percent partial CCS to meet the final standard would see an increase in water consumption (the difference between the predicted water withdraw and discharge) of about 6.4 percent compared to an SCPC with no CCS and the same net power output. Further, the EPA expressed the view that there would be additional opportunities to minimize the water usage at such a facility. For example, the SaskPower Boundary Dam Unit #3 post-combustion capture project captures water from the flue gas and recycles the water, resulting in decreased withdrawal of fresh water. In addition, while the Agency did not find IGCC to be the BSER, the predicted water consumption for the new IGCC unit was nearly 20 percent less than that predicted for the new SCPC unit without CCS (and almost 25 percent less than the SCPC unit meeting the final standard). The EPA also predicted that water consumption at a new NGCC unit would be less than half that for a new SCPC EGU with the same net output.

In the 2015 Rule, the EPA's water use increase comparison, which was summarized in Table 13 of the 2015 final rule preamble (80 FR 64592), was evaluated based on a bituminous-fired EGU with a wet scrubber and a cooling tower. While this is one common configuration for an EGU boiler and associated air pollution control device, this does not account for other boiler configurations and other air pollution control devices. Certain regions of the country with an arid climate and/or scarce water availability often use boiler and pollution control devices that minimize water use. While the absolute amount of water required for CO_2 capture equipment is relatively constant on a gallon per ton of captured CO_2 basis across various boiler types, the percentage increase in water requirements is not. A more appropriate percentage increase comparison for arid western markets and other locations in water-scarce environments is a subbituminous-fired PC unit with spray drying or a fluidized bed unit and a cooling tower. To estimate the increased water consumption for low rank coal-fired EGUs, the EPA used the NETL partial capture report for bituminous coal-fired EGUs to determine the increased water requirements per amount of CO_2 captured. The EPA then applied the increased water use relationship to the 2011 baseline report that included model plants burning low rank coal.

As shown in Table 8, the percent increase in water use for EGUs burning low rank coals is four times as large as for bituminous-fired EGUs. The EPA is proposing that this increase in water requirements is so great that it could be prohibitively expensive for developers to secure sufficient quantities of water in arid regions of the country.[85] [86]

TABLE 8—PREDICTED WATER CONSUMPTION

Technology	Raw water consumption (gpm/MWnet) [1]	Increase in water use compared to no CCS (%) [87]
SCPC − no CCS (bit)	7.4	
SCPC + ~16% CCS (bit)	7.9	7.7
SCPC − no CCS (low rank))	3.8	
SCPC + ~ 26% CCS (low rank)	4.9	28

[1] MWnet = megawatts-net.
[2] SCCFB = supercritical circulating fluidized bed.

In addition to the configurations cited in the NETL report, other boiler configurations use even less water. For example, Black Hills Power Corporation's 110-MW Wygen III is a pulverized coal power plant near Gillette, Wyoming. The plant, which came online in 2010, fires Powder River Basin coal and has an air pollution control system comprised of selective catalytic reduction, dry flue gas desulfurization (FGD), and a fabric filter baghouse. This type of ''dry'' plant was built with minimal water requirements due to dry cooling and dry lime FGD for acid gas control. As described elsewhere in the preamble, this type of boiler design is one of the configurations likely to be considered for future coal-fired EGUs. However, carbon capture technologies are limited to using conventional wet cooling technologies. The EPA is unaware of any demonstration, pilot, or large-scale projects using dry cooling technologies with carbon capture technologies. Therefore, requiring CCS on a plant of this design would substantially increase the plant's water-use requirements.

All CCS systems that are currently available require substantial amounts of water to operate. These water requirements would limit the geographic availability of potential future EGU construction to areas of the country with sufficient water resources.

U.S. DOE NETL, *Water Requirements for Existing and Emerging Thermoelectric Plant Technologies* at 13 DOE/NETL–402/080108, August 2008, April 2009 revision.

[85] Part of the rationale that the water requirements are too great is that the water requirements for partial CCS are roughly double that of the water requirements for a spray dryer used for SO_2 control.

[86] In the 2015 final rule, the EPA referenced SaskPower Boundary Dam's lignite-fired Unit #3 post-combustion capture project that recovers water from the flue gas and recycles it, resulting in decreased need for withdrawal of fresh water from the adjacent reservoir. However, specific data on how much water was captured/saved was not cited. In retrospect, the EPA now believes that it should have considered that for new lignite-fired power plants owners/operators would likely dry the lignite prior to combustion. Drying lignite both decreases the capital cost of a new boiler island and increases boiler efficiency. However, it results in less water in the flue gas, limiting the amount that can be captured/recycled. The same might be the case for new subbituminous coal-fired EGUs—they would likely dry the coal prior to combustion so less water would be available in the flue gas for recovery and reuse.

[87] In the 2015 rulemaking, the raw water consumption for a SCPC with no CCS (bit) was reported as 4,095 gallons per minute (gpm) instead of 4,045 gpm. This resulted in a reported increase in water use of 6.4 percent instead of 7.7 percent.

To establish water availability, the EPA has, for this proposal, reviewed annual average rainfall totals as an estimation of water availability. This approach indicates that the Western U.S. (*i.e.,* areas west of a line running from central Texas to North Dakota), excluding the Pacific Northwest, has lower amounts of water available for EGUs. In addition, a comparison of areas of the country with lower rainfall amounts shows considerable overlap with areas of the country with sequestration sites. This suggests that many sequestration sites might not have sufficient water resources to operate CO_2 capture equipment. Therefore, this, in combination with the EPA's proposed determination that its earlier understanding of the scope of geologic sequestration site availability was an overestimation (by some 4 percent), has led the EPA to propose a revision to its 2015 findings and a new determination that the overall geographic availability of CCS is too limited to be considered as BSER.

In the 2015 Rule, EPA also stated that a new IGCC unit required nearly 20 percent less water than a new bituminous coal-fired SCPC unit without CCS (and almost 25 percent less than the SCPC unit meeting the final standard). The DOE/NETL reports indicate that IGCC designs are available that use less water than comparative PC units for low rank coals as well. However, in an April 2017 independent engineering report on the Kemper IGCC Project,[88] one of the concerns noted was the underestimation of the amount of water needed for the process water system. The report noted that the initially planned 5 million gallons of storage was insufficient, that a new 1.7-million-gallon temporary tank was to be installed and that additional permanent water storage tank capacity should be considered. Based on this, the EPA is soliciting comment on whether IGCC reduces the amount of water use by coal-fired EGUs (Comment C–9).

c. Review of Technical Feasibility of Carbon Capture Equipment

In the 2015 Rule, the EPA determined that CO_2 capture technology was technically feasible based on EGUs that had previously and were currently using post-combustion carbon capture technology (especially Boundary Dam), commercial vendors that offered carbon capture technology and other performance guarantees, a review of the literature, and industry and technology developers' pronouncements of the feasibility and availability of CCS technologies. Since the 2015 rulemaking, the Petra Nova CCS project, located at NRG's W.A. Parish power generating station near Houston, Texas, has begun operations, and is reported to be the world's largest post-combustion carbon capture system.[89]

While the carbon capture technology at the Boundary Dam project is currently operating, that project experienced multiple issues with the performance of the capture technology during its first year of operation (2014–15). During that time, the capture equipment was operating with lower reliability than designed, and, as a result, SaskPower renegotiated its CO_2 supply contract with Cenovus to avoid paying penalties for not supplying the agreed amount of CO_2 for the company's EOR projects. These problems included the amine chemistry and the CO_2 compression system. While the Petra Nova project is currently operating, it has not demonstrated the integration of the thermal load of the capture technology into the EGU steam generating unit (*i.e.,* boiler) steam cycle. Rather, the parasitic electrical and steam load are supplied by a new 75 MW co-located natural gas-fired CHP facility. The EPA solicits comment on whether Boundary Dam's first-year operational problems cast doubt on the technical feasibility of fully integrated CCS (Comment C–10). For example, would an EGU with a fully integrated steam cycle that draws steam from the steam turbine to regenerate the amine be able to operate during periods when the carbon capture system is not operating?

The EPA notes that while both these projects are currently operating, both received significant government support to mitigate the financial risks associated with the CCS technology. Because no independent commercial CCS projects are in operation, the EPA solicits comment on whether the fact that Boundary Dam and Petra Nova were dependent on government support casts doubt on the technical feasibility of CCS, *e.g.,* whether it raises concerns as to the extent to which developers are willing to accept the risks associated with the operation and long-term reliability of CCS technology (Comment C–11).

While the EPA did not find that a new IGCC EGU is part of the final BSER, the Agency did note that IGCC without CCS is a viable alternative compliance option. However, both the Edwardsport and Kemper IGCC facilities had significant cost overruns. In fact, the Kemper IGCC's technology challenges, escalating costs, and project management issues resulted in the company suspending startup and operations activities involving the lignite gasification portion of the energy facility, leaving only the natural gas combined cycle plant in operation.[90] The EPA solicits comment on the extent to which the issues with these IGCC EGUs cast doubt on the economic viability of IGCC as an option for new generation (Comment C–12).

B. Identification of the Revised BSER

The EPA evaluated six different control technology configurations as potentially representing the BSER for new and reconstructed coal-fired EGUs: (1) The use of partial CCS, (2) conversion to (or co-firing with) natural gas, (3) the use of CHP, (4) the use of a hybrid power plant, (5) the use of IGCC technology, and (6) efficient generation. This section discusses each of these alternatives, including the technical systems that the EPA considered for the BSER, evaluations of each system, and the reasons for determining that the most efficient generating technology meets the criteria to qualify as the BSER. The discussion includes the rationale for selecting the proposed standards of performance based on those BSER.

As noted above, the EPA determines the best demonstrated system based on the following key considerations, among others:

- The system of emission reduction must be technically feasible.
- The costs of the system must be reasonable. The EPA may consider the costs on the source level, the industrywide level, and, at least in the case of the power sector, on the national level in terms of the overall costs of electricity and the impact on the national economy over time.

[88] This project received federal assistance under the Energy Policy Act of 2005 (EPAct05). *See* 2015 rule, 80 FR at 64526, n.74. The EPA is not proposing to revise or re-open the interpretation of EPAct05 that the EPA included in the 2015 rule. *Id.* at 64541–64542. Thus, because the EPA is considering information about the Kemper project in conjunction with other information that is not from facilities affected by EPAct05, EPAct05 does not preclude the EPA from considering such Kemper information.

[89] As with the Kemper project discussed above, this project received federal assistance under EPAct05. *See* 2015 rule, 80 FR at 64526, n.74. As with the Kemper project, because EPA is considering information about the Petra Nova project in conjunction with other information that is not from facilities affected by EPAct05, EPAct05 does not preclude EPA from considering the Petra Nova information.

[90] URS Corp., *IM Monthly Report—Mississippi Public Service Commission: Kemper IGCC Project,* April 2017, available at *http://www.psc.state.ms.us/executive/pdfs/2017/Kemper/Monthly%20Report%20April%202017%20Executive%20Summary.pdf.*

• The EPA must also consider energy impacts, and, as with costs, may consider them on the level of the source, the region, and on the nationwide structure of the power sector over time.

• According to the D.C. Circuit caselaw, the EPA must consider the amount of emissions reductions that the system would generate, and that CAA section 111 is designed to promote the development and implementation of technology. Moreover, the EPA has discretion to weigh these various considerations, may determine that some merit greater weight than others, and may vary the weighting depending on the source category.

1. Partial CCS

As described previously, under the revised analysis set forth in this proposal, the EPA proposes that the cost of partial CCS is not reasonable. In addition, when the availability of water and geologic sequestration sites are considered together, the EPA finds that partial CCS is not widely geographically available. In addition, the EPA is soliciting comment on whether there is sufficient information about the long-term reliability of carbon capture technology and sequestration capture technology to assess the technical feasibility of CCS (Comment C–13). Therefore, the EPA proposes to rescind our finding that partial CCS satisfies the BSER criteria and proposes to find that it does not.

2. Conversion to or Co-Firing With Natural Gas

While co-firing with natural gas in a utility steam generating unit a technically feasible option to reduce CO_2 emission rates, it is an inefficient way to generate electricity compared to use of an NGCC. For cases where the natural gas could be co-fired without any capital investment (*e.g.,* sufficient natural gas is available at the site) or impact on the performance or operation of the affected EGU, the costs of CO_2 reduction would be between approximately $40 to $70 per ton of CO_2 avoided (that is, $40/ton for bituminous coal and $70/ton for subbituminous coal), depending on the coal rank burned in the boiler. This calculation only accounts for the relative costs and CO_2 emission rates of the fuel and does not account for potential adverse or positive impacts on the operation of the boiler. While natural gas prices have fallen significantly over the past decade, long term price projections forecast that natural gas will still be significantly more expensive than coal on a $/MMBtu basis. The higher fuel costs from co-firing would increase both the LCOE and variable operating costs of the unit. As described earlier, due to economic dispatch, the unit would be expected to have lower electricity sales, and therefore generate less revenue and less marginal and overall profit. Further, if an owner/operator is required to burn natural gas for compliance purposes, it would likely have to enter into firm service contracts as opposed to interruptible service contracts for natural gas, which would increase its costs for natural gas. Potential positive aspects include a reduction in pre-post combustion control criteria pollutant and HAP emission rates. Due to these lower pre-post combustion emission rates, post-combustion control requirements are reduced and savings could be realized due to both lower capital and O&M post combustion control costs and/or the cost of emission allowances under certain pollution control programs. Most pollutants, and especially NO_X, would be reduced in proportion to the amount of natural gas burned.

Natural gas reburning (NGR) is a combustion technology in which a portion of the main fuel heat input is diverted to locations above the burners, creating a secondary combustion zone called the reburn zone. In NGR, natural gas is injected to produce a slightly fuel rich reburn zone. Overfire air (OFA) is added above the reburn zone to complete burnout. NGR requires 15 to 20 percent of furnace heat input from natural gas and OFA and has been demonstrated to reduce NO_X emissions by 39 to 67 percent on several existing coal-fired boilers in applications ranging in size from 33 to 600 MW in the U.S. and up to 800 MW internationally. With NGR at 15 and 20 percent of the heat input to a coal-fired boiler, the CO_2 emission rate would be reduced by 6 to 10 percent.

Fuel lean gas reburning (FLGR™), also known as controlled gas injection, is a process in which natural gas is injected above the main combustion zone at a lower temperature zone than in NGR. FLGR™ is different from NGR because the gas is injected in a manner that optimizes the furnace's stoichiometry on a localized basis. By doing this, the process avoids creating a fuel-rich zone and maintains overall fuel-lean conditions. The FLGR™ technology achieves NO_X control using less than 10 percent natural gas heat input without the requirement for OFA. FLGR™ has a capital cost of approximately $8/kW [91] and been demonstrated to reduce NO_X emissions by 33 to 45 percent. At a 10 percent heat input reburn rate, the CO_2 emission rate of a coal-fired EGU would be reduced by 4 to 5 percent. Based strictly on the difference in fuel prices, co-firing 10 percent natural gas would only increase the LCOE of a coal-fired EGU by approximately 2 or 3 percent. However, variable operating costs would increase between approximately 7 to 9 percent, impacting dispatch and energy revenue for the EGU.

In addition, while many recently constructed coal-fired power plants routinely use natural gas or other fuels such as low sulfur fuel oil for start-up operations and, if needed, to maintain the EGU in ''warm stand-by,'' some areas of the U.S. have natural gas pipeline infrastructure limitations. These areas either currently lack access to natural gas transportation infrastructure or face capacity constraints in their existing natural gas pipelines (*i.e.,* they are not able to greatly increase purchase volumes with the existing infrastructure).[92] For new coal-fired EGUs wishing to locate in these areas, it could be either infeasible or extremely costly to co-fire natural gas. The EPA solicits comment on the cost to add natural gas capability to areas of the county without sufficient infrastructure to support a new natural gas-fired EGU (Comment C–14).

While co-firing natural gas might be a viable option for specific coal-fired EGUs, the EPA is not proposing natural gas co-firing as part of the BSER for multiple reason. First, as discussed previously, a significant benefit of a new coal-fired power plant is the fuel diversity value that it brings. Requiring the EGU to burn natural gas defeats the purpose of constructing the EGU in the first place. Further, not all areas of the country have cost-effective access to natural gas. Co-firing natural gas is an inefficient use of the nation's natural gas resources, which is relevant under the ''energy requirements'' criterion for BSER. Combined cycle EGUs are more efficient at using natural gas to generate electricity and it would not be environmentally beneficial for utilities to combust natural gas in less steam generating units to satisfy a facility specific emissions standard. Finally, at this time, the EPA does not have

[91] Breen, *Fuel Lean Gas Reburn (FLGR) Solutions,* available at *http://breenes.com/wp-content/uploads/2017/07/FLGR_ljv4singles.pdf.*

[92] Maps of natural gas pipelines and underground storage facilities are available from EIA, *https://www.eia.gov/naturalgas/archive/analysis_publications/ngpipeline/index.html.* Information on pending projects are available from EIA and the Federal Energy Regulatory Commission (FERC), *https://www.eia.gov/naturalgas/pipelines/EIA-NaturalGasPipelineProjects.xlsx* and *https://www.ferc.gov/industries/gas/indus-act/pipelines/pending-projects.asp*

sufficient information to analyze the overall impact of co-firing natural gas, particularly impacts on dispatch.

3. Combined Heat and Power (CHP)

CHP, also known as cogeneration, is the simultaneous production of electricity and/or mechanical energy and useful thermal output from a single fuel. CHP requires less fuel to produce a given energy output, and because less fuel is burned to produce each unit of energy output, CHP reduces air pollution and GHG emissions. CHP has lower emission rates and can be more economic than separate electric and thermal generation. However, a critical requirement for a CHP facility is that it primarily generates thermal output and generates electricity as a byproduct and must therefore be physically close to a thermal host that can consistently accept the useful thermal output. For coal-fired EGUs, it can be particularly difficult to locate a thermal host with sufficiently large thermal demands such that the useful thermal output would impact the emissions rate. The refining, chemical manufacturing, pulp and paper, food processing, and district energy industries tend to have large thermal demands. However, the thermal demand at these facilities is generally only sufficient to support a smaller coal-fired power plant, approximately a maximum of 100 MW. This would limit the geographically available locations where new coal-fired generation could be constructed in addition to limiting size. Furthermore, even if a sufficiently large thermal host were in close proximity, the owner/operator of the EGU would be required to rely on the continued operation of the thermal host for the life of the EGU. If the thermal host were to shut down, the EGU would be unable to comply with the emissions standard. This reality would likely result in difficulty in securing funding for the construction of the EGU and could also lead the thermal host to demand discount pricing for the delivered useful thermal output. For these reasons, the EPA proposes it is not practicable to find that CHP is BSER.

4. Hybrid Power Plant

Hybrid power plants combine two or more forms of energy input into a single facility with an integrated mix of complementary generation methods. While there are multiple types of hybrid power plants, the most relevant type for this proposal is the integration of solar energy (*e.g.,* concentrating solar thermal) with a fossil fuel-fired EGU. Both coal-fired and NGCC EGUs have operated using the integration of concentrating solar thermal energy for use in boiler feed water heating, preheating makeup water, and/or producing steam for use in the steam turbine or to power the boiler feed pumps.

One of the benefits of integrating solar thermal with a fossil fuel-fired EGU is the lower capital and O&M costs of the solar thermal technology. This is due to the ability to use equipment (*e.g.,* HRSG, steam turbine, condenser, *etc.*) already included at the fossil fuel-fired EGU. Another advantage is the improved electrical generation efficiency of the non-emitting generation. For example, solar thermal often produces steam at relatively low temperatures and pressures, and the conversion of the thermal energy in the steam to electricity is relatively low. In a hybrid power plant, the lower quality steam is heated to higher temperatures and pressures in the boiler (or HSRG) prior to expansion in the steam turbine, where it produces electricity. Upgrading the relatively low-grade steam produced by the solar thermal facility in the boiler improves the relative conversion efficiencies of the solar thermal to electricity process. The primary incremental costs of the non-emitting generation in a hybrid power plant is the costs of the mirrors, additional piping, and a steam turbine that is 10 to 20 percent larger than that in a comparable fossil only EGU to accommodate the additional steam load during sunny hours. A drawback of integrating solar thermal is that the larger steam turbine will operate at part loads and reduced efficiency when no steam is provided from the solar thermal panels during periods when the sun is not shining (*i.e.,* the night and cloudy weather). This limits the amount of solar thermal that can be integrated into the steam cycle at a fossil fuel-fired EGU.

In the 2018 Annual Energy Outlook [93] (AEO 2018), the levelized cost of concentrated solar power (CSP) without transmission costs or tax credits is $161/MWh. Integrating solar thermal into a fossil fuel EGU reduces the capital cost and O&M expenses of the CSP portion by 25 and 67 percent compared to a stand-alone CSP EGU respectively.[94] This results in an effective LCOE for the integrated CSP of $104/MWh. Assuming the integrated CSP is sized to provide 10 percent of the maximum steam turbine output and the relative capacity factors of the coal-fired boiler and the CSP (those capacity factors are 85 and 25 percent, respectively) the overall annual generation due to the concentrating solar thermal would be 3 percent of the hybrid EGU output. This would result in a three percent reduction in the overall CO_2 emissions and a one percent increase in the LCOE, without accounting for any reduction in the steam turbine efficiency. However, these costs do not account for potential reductions in the steam turbine efficiency due to being oversized relative to a non-hybrid EGU. Without this information, the EPA does not have sufficient information to evaluate costs and overall impact, and therefore cannot propose this technology as the BSER.

In addition, solar thermal facilities require locations with abundant sunshine and significant land area in order to collect the thermal energy. Existing concentrated solar power projects in the U.S. are primarily located in California, Arizona, and Nevada with smaller projects in Florida, Hawaii, Utah, and Colorado. Not all areas of the U.S. have both sufficient space and the abundant sunshine to successfully operate a hybrid power plant. The EPA proposes that due to the limited geographic availability of concentrated solar thermal projects, the Agency cannot propose this technology as BSER.

An alternate, but similar, approach for coal-fired EGUs to integrate lower-emitting generation would be to use natural gas-fired combustion turbines, fuel cells, or other combustion technology. These alternatives can reheat or preheat boiler feed water (minimizing the steam that is otherwise extracted from the steam turbine), preheat makeup water and combustion air, produce steam for use in the steam turbine or to power the boiler feed pumps, or use the exhaust directly in the boiler to generate steam. In theory, this could lower generation costs as well the GHG emissions rate for a coal-fired EGU. The EPA is aware of only one coal-fired EGU currently integrating lower-emitting combustion technology,[95] does not have sufficient information to evaluate costs, and therefore cannot propose this technology as the BSER.

[93] EIA, *Annual Energy Outlook 2018,* February 6, 2018, available at *https://www.eia.gov/outlooks/aeo/.*

[94] B. Alqahtani and D. Patiño-Echeverri, Duke University, Nicholas School of the Environment, ''Integrated Solar Combined Cycle Power Plants: Paving the Way for Thermal Solar,'' *Applied Energy* 169:927–936 (2016).

[95] The Gerstein power plant, unit K, in Germany integrates a natural gas-fired combustion turbine that discharges the exhaust directly into the coal-fired boiler. This essentially creates a combined cycle EGU with a coal-fired heat recovery steam generator.

5. IGCC

The EPA also considered whether IGCC technology represents the BSER for new power plants using coal or other solid fossil fuels. While gasification is available and used in other industrial sectors (*e.g.,* petroleum refining) there are relatively few IGCC EGUs. According to the NETL baseline fossil reports, IGCC units are projected to have a lower gross-output based emission rates compared to SCPC. However, the design net emission rates and absolute amount of emissions to the atmosphere tend to be materially similar so there are limited, if any, net GHG benefits. Furthermore, the emissions data for the IGCC facilities in the EPA database does not include the output from the steam turbine. As a result, it is not possible to verify the gross emissions rate or estimate the net emissions rate. Therefore, the EPA does not currently have sufficient information based on actual operating data to evaluate whether IGCC meets the BSER requirements. In addition, the NETL baseline fossil fuel reports indicate that IGCC LCOE costs are 20 percent higher, and the incremental generating costs are 4 percent higher, than a comparable SCPC. However, the two most recent IGCC EGUs constructed in the U.S. (Edwardsport and Kemper) both experienced significant cost overruns. In fact, the technical complexity and costs of the Kemper project were so great that the gasification project was abandoned and the facility is currently operating as a natural gas-fired combined cycle facility. Based on consideration of these factors, the EPA is not proposing IGCC as the BSER.

6. Energy Efficient Power Generation

This section describes the technology that the EPA proposes for the BSER: the most efficient generation technology available, which is the use supercritical [96] steam conditions (*i.e.,* a SCPC or supercritical circulating fluidized bed (CFB) boiler) for large EGUs, and the use of the best available subcritical steam conditions for small EGUs in combination with the best operating practices and dry cooling. The use of higher steam temperatures and pressures (*e.g.,* supercritical steam conditions) increases the efficiency of converting the thermal energy in the steam to electrical energy. Best operating practices, include, but are not limited to, installing and maintaining equipment (*e.g.,* economizers, feedwater heaters, etc.) in such a way to maximize overall efficiency and to operate the steam generating unit to maximize overall efficiency (*e.g.,* minimize excess air, optimize soot blowing, etc.). The cooling (*i.e.,* condensing) system also has a significant impact on efficiency. Once through cooling systems use an open system where cooling water is extracted directly from a water body and returned to the same water body at a high temperature. This type of cooling result in the most efficient operation. However, once through system have greater environmental impacts and new EGUs use either cooling towers or dry cooling systems. Cooling towers are closed systems where the water extracted for cooling is evaporated in the cooling tower. Cooling towers reduce water impacts compared to once through systems, but still require substantial amounts of water to operate. Dry cooling systems use air heat exchangers to provide cooling and minimize water impacts. However, these systems are also the least efficient.

a. Reasonable Costs

Advanced generation technologies enhance operational efficiency compared to lower efficiency designs. Such technologies are technically feasible and present little incremental capital cost compared to other types of technologies that may be considered for new and reconstructed sources. In addition, due to the lower variable operating costs, more efficient designs would be expected to dispatch more often and sell more electricity, thereby offsetting increases in capital costs. It should be noted that this cost evaluation is not an attempt to determine the affordability of advanced generation in a business or economic sense (*i.e.,* the reasonableness of the imposed cost is not determined by whether there is an economic payback within a predefined time period). Table 9 lists the capital costs, variable operating costs, design emission rates, and LCOE for various boiler designs.

TABLE 9—COST AND EMISSION RATES OF COAL-FIRED EGUS (2016 $) [97]

Technology [98]	Total as spent capital ($/kW)	Variable operating costs ($/MWh)	Design emissions rate (lb CO_2/MWh-net)	LCOE ($/MWh)
Subcritical PC (bit)	2,850	32.3	1,780	81.2
Supercritical PC (bit)	2,940	31.3	1,710	81.7
IGCC (bit)	3,590	32.0	1,730	97.9
Supercritical PC (low rank)	3,340	28.0	1,890	85.2
Ultra-supercritical PC (low rank)	3,520	27.4	1,840	87.6

b. Non-Air Quality Health and Environmental Impacts and Energy Requirements

Highly efficient generation reduces all environmental and energy impacts compared to less efficient generation. Even when operating at the same input-based emissions rate, the more efficient a unit is, the less fuel is required to produce the same level of output, so overall emissions are reduced for all pollutants. Supercritical steam conditions, compared to subcritical, reduce all pollutants between approximately 3 to 5 percent. More

[96] Subcritical coal-fired boilers are designed and operated with a steam cycle below the critical point of water (22 MPa (3,205 psi)). EGUs using supercritical steam conditions operate at pressures greater than 22 MPa and temperatures greater than 550 °C (1,022 °F). Increasing the steam pressure and temperature increases the amount of energy within the steam, so that more energy can be extracted by the steam turbine, which in turn leads to increased efficiency and lower emissions.

[97] The primary sources of information are the NETL baseline fossil reports. The EPA converted the dollar year to 2016 values and estimated low rank subcritical and bituminous ultra-supercritical based on the ratios in the relevant baseline fossil reports. Consistent with the NETL partial CCS approach, costs are ''next-of-a-kind'' rather than first of a kind (80 FR at 64,570/3). First of a kind costs are higher than ''next-of-a-kind'' costs but are expected to decrease (as is normally the case) with the completion of additional projects and DOE/NETL research.

[98] The NETL design values are 16.5 MPa (2,400 pounds per square inch gauge (psig)) () and 566 °C (1,050 °F) for subcritical EGUs, 24 MPa (3,500 psig) and 593 °C (1,100 °F) for supercritical EGUs, and 28 MPa (4,000 psig) and 650 °C (1,200 °F) for ultra-supercritical EGUs.

efficient EGUs also have lower auxiliary (*i.e.,* parasitic) loads so that impacts on energy requirements are also reduced.

c. Extent of Reductions in CO_2 Emissions

In the 2015 Rule, the EPA found that highly efficient generation did not represent BSER in part because it would not result in meaningful emission reductions and did not promote the development of control technology. That conclusion was based on the assumption that any new coal-fired EGU built in the U.S. would use highly efficient generation even in the absence of 40 CFR part 60, subpart TTTT.

Close to 90 percent of the large coal-fired EGUs that have commenced operation since 2010 in the U.S. use either supercritical steam conditions or IGCC technology. The remainder of the capacity uses subcritical steam conditions. However, according to data submitted to the EPA's Clean Air Markets Division (CAMD), the average 2017 reported emissions rate of all large coal-fired boilers that commenced operation since 2010 was 1,938 lb CO_2/MWh-gross. This is two percent higher than the proposed standard. The sole small coal-fired EGU reporting emissions that commenced operation since 2010 in the U.S. uses subcritical steam conditions and had a reported annual emissions rate of 2,200 lb CO_2/MWh-gross, nine percent higher than the proposed standard. Therefore, if a new coal-fired EGU were to be constructed, the EPA estimates that the proposed BSER standards would result in reductions in emissions of approximately two percent for large EGUs and nine percent for small EGUs when compared to the expected emissions for new EGUs absent an NSPS establishing standards for GHG emissions. Fuel costs makeup a significant portion of the variable operating costs of a coal-fired EGUs and owners/operators of EGUs currently have a financial incentive to maximize efficiency and minimize CO_2 emissions. While achievable, the proposed emission rates would require owners/operators of a new coal-fired EGU to both construct a highly efficient EGU and operate and maintain it to minimize CO_2 emissions.

d. Technical Feasibility

The use of supercritical steam conditions has been demonstrated by multiple facilities since the 1970s. Between 2013 and 2017, 327 gigawatts (GW) of coal-fired EGUs entered operation globally in 15 countries. The new capacity is split roughly equally between subcritical, supercritical, and ultra-supercritical steam conditions. Subcritical units tend to be smaller (*i.e.,* less than 300 MW) and supercritical units tend to be approximately 500 MW. Ultra-supercritical EGUs tend to be larger (*e.g.,* 800 MW) and have been built in China, Germany, South Korea, Netherlands, Malaysia, and Japan. Materials capable of withstanding ultra-supercritical steam conditions of 30 MPa (4,350 psi) and 620 °C (1,120 °F) have been demonstrated internationally at coal-fired boilers.[99] In addition, vendors are offering designs capable of withstanding advanced ultra-supercritical steam conditions of 33 MPa and 670 °C.[100] Furthermore, using supercritical steam also allows the use of a second reheat cycle, which further increases efficiency.

As stated in the 2015 Rule, the smallest supercritical coal-fired EGU is approximately 200 MW, and steam turbines that operate on supercritical steam are currently not commercially available for smaller coal-fired EGUs. Consequently, developers of a small EGU that wished to use supercritical steam conditions would have to have a steam turbine designed specifically for that project, substantially increasing the cost of the project. Therefore, for smaller new and reconstructed EGUs the maximum economically viable steam pressure and temperature for which steam turbines are currently available are 21 MPa (3,000 psi) and 570 °C (1,060 °F). Above this pressure, the steam would be supercritical. Also, using subcritical steam conditions limits the steam cycle to use of a single steam reheat cycle. Therefore, it is not technically feasible for smaller EGUs to use a second reheat cycle to improve efficiency.

e. Promotion of the Development and Implementation of Technology

As noted above, the case law makes clear that the EPA is to consider the effect of its selection of BSER on technological innovation or development, but that the EPA also has the authority to weigh this against the other factors. Selecting highly efficient generation technology as the BSER offers an opportunity to encourage the development and implementation of improved control technology. This technology is readily transferrable to other countries, existing EGUs, and other industries.

According to EIA, demand in India and Southeast Asia is projected to drive an increase in coal use over the next two decades. Coal is often the fuel of choice because it is abundant, inexpensive, secure, and easy to store. Clean coal technologies are critical to ensuring that these economies develop in a more environmentally sustainable way. According to the World Electric Power database, sixty percent of the new coal-fired capacity in India and Southeast Asia between 2013 and 2017 uses subcritical steam conditions. Although supercritical technology is already developed, establishing it as the basis for control requirements in the U.S. for new and reconstructed sources would help establish it in other nations, resulting in a reduction in global CO_2 emissions. The EPA considers that the proposed BSER will promote the development and implementation of viable control technologies.

f. Nationwide, Longer-Term Perspective of Impacts on the Energy Sector

Designating the most efficient generation technology as the BSER for new and reconstructed coal-fired utility boilers and IGCC units will not have significant impacts on nationwide electricity prices. This is because (1) the additional costs of the use of efficient generation will, on a nationwide basis, be small because few, if any, new coal-fired projects are expected, and because at least some of these can be expected to incorporate efficient generation technology in any event; and (2) the technology does not add significant costs. For similar reasons, designation of the most efficient generation technology as the BSER for reconstructed new coal-fired utility boilers and IGCC units will not have adverse effects on the structure of the power sector, will promote fuel diversity, and will not have adverse effects on the supply of electricity.

Based on the reasonable cost, technical feasibility, and emission reductions the EPA proposes that efficient generation in combination with the best operating practices is the BSER for new coal-fired EGUs.

C. Reconstructed EGUs

In the 2015 Rule, the EPA explained the background of, and requirements for, reconstructed EGUs, evaluated various control technology configurations to determine the BSER for reconstructed coal-fired boiler and IGCC EGUs, and selected efficiency improvements achieved through the use of the most efficient generation technology. The EPA explained that this technology was technically feasible, had sufficient emission reductions, had reasonable costs, and had some opportunity for technological

[99] Isogo unit 2 (located in Japan) has a reheat temperature of 620 °C and Avedore 2 (located in Denmark) operates at 30 MPa.

[100] *https://www.ge.com/power/steam/steamh.*

innovation. The EPA is taking the same approach in this rulemaking and is not proposing to change the BSER technology. However, since the BSER is the same, the Agency is proposing to use the emissions analysis as for new EGUs for reconstructed EGUs as well. For each of the subcategories, that is, the BSER and emissions standard for reconstructed EGUs is the same as for new EGUs.

D. Coal Refuse Subcategory

Coal refuse (also called waste coal) is a combustible material containing a significant amount of coal mixed with rock, shale, slate, clay and other material that is reclaimed from refuse piles remaining at the sites of past or abandoned coal mining operations. In the April 2012 proposal, the EPA solicited comment on subcategorizing EGUs that burn over 75 percent coal refuse on an annual basis (the EGU NSPS for criteria pollutants contain such a subcategory). Multiple commenters supported a subcategory, citing numerous environmental benefits of remediating coal refuse piles. The EPA declined to adopt a subcategory and explained that the costs faced by coal refuse facilities to install partial CCS were similar for coal-fired EGUs burning any of the primary coals (*i.e.,* bituminous, subbituminous, and lignite). Further, the final applicable requirements and standards in the rule did not entirely preclude the development of new coal refuse-fired units without CCS, for example, through the exclusion for industrial CHP units. Many existing coal refuse-fired units are relatively small and designed as CHP units. Due to the expense of transporting coal refuse long distances, the EPA projected that any new coal refuse-fired EGU would likely be relatively small. Moreover, sites with sufficient thermal demand exist such that the unit could be designed as an industrial CHP facility and the requirements of 40 CFR part 60, subpart TTTT would not apply.

Under the 2015 partial CCS BSER determination, due to lower efficiencies and higher uncontrolled emission rates, coal refuse-fired EGUs would have had to install a slightly higher percentage of partial CCS, increasing costs roughly in proportion to the percentage increase in partial CCS. These increase in costs were determined to be sufficiently similar and a subcategory for coal refuse-fired EGUs was not necessary. However, as described previously the proposed BSER (and the corresponding emissions rate) for coal-fired EGUS (including coal refuse-fired EGUs) is efficient generation and not the use of partial CCS. Therefore, the cost rationale for not providing a subcategory for coal refuse-fired EGUs is not necessarily applicable. For multiple reasons, coal refuse-fired EGUs have higher uncontrolled emission rates. Coal refuse generally has lower energy density (British thermal units per pound (Btu/lb) of fuel) due to its high ash content along with a higher emissions rate on a pound of CO_2 per million British thermal unit (lb CO_2/MMBtu) basis. Unlike with ''wet'' coals such as lignite, there are limited options for upgrading the energy density of coal refuse. This lower energy density leads to inherently lower efficiency steam generating units. Furthermore, certain coal refuse piles have high sulfur contents. While remediating these piles through combustion provides significant multimedia environmental benefits, combusting these fuels presents challenging problems. To control sulfur emissions, significant quantities of limestone are added to the fluidized bed boilers. This not only decreases efficiency (due to the additional fuel required to calcine the limestone) but leads to chemically created CO_2 (released when the limestone is calcined to lime) that is released through the stack. These factors make it difficult for coal refuse-fired EGUs to achieve the same output-based GHG emission rates of EGUs burning primary coals. While coal refuse-fired EGUs do not report sufficient emissions data to the EPA's CAMD to determine their emission rates, based on normalization of emissions data, a coal refuse-fired EGU would emit approximately 20 percent more than a comparable bituminous-fired EGU. Therefore, if there is not a subcategory for coal refuse-fired EGUs, a developer of a new coal refuse-fired EGU would be required to install controls beyond the BSER technology basis.

In the 2015 Rule, the EPA concluded that, due to their relatively small size, new coal refuse-fired EGUs would likely be designed as CHP units and would therefore not be subject to 40 CFR part 60, subpart TTTT. However, the EPA has conducted a more recent analysis of the makeup of existing coal refuse-fired EGUs, which calls this conclusion into question. There are 18 existing coal refuse-fired EGUs that range from 400 to 2,500 MMBtu/h heat input. Only half of these units are CHP units, and the other half are strictly electricity production facilities. As stated previously, coal refuse-fired EGUs tend to be located close to existing coal refuse piles, and there is no assurance that a suitable thermal host will locate in those areas. Without a thermal host, the coal refuse-fired unit would not qualify as a CHP unit, and, instead, would become subject to 40 CFR part 60, subpart TTTT. Consequently, the EPA is proposing to revise our conclusion that all new coal refuse-fired EGUs have the ability to avoid applicability with 40 CFR part 60, subpart TTTT.

Considering these factors, the EPA proposed that the BSER for coal refuse-fired EGUs is the use of the best available subcritical steam conditions in combination with the best operating practices. One benefit of creating a subcategory for coal refuse-fired EGUs is to not discourage the development of these projects and to recognize the multimedia environmental benefits of remediating coal refuse piles.[101] The non-air quality environmental benefits include the remediation of acid seepage and leachate production, low soil fertility, and reclaiming land for productive use. An additional consideration is that existing coal refuse piles are slowly combusting in place and the CO_2 will eventually be released to the atmosphere so net GHG emissions are lower than those measured at the stack.

E. Determination of the Level of the Standard

Once the EPA has determined that a particular system or technology represents BSER, the CAA authorizes the Administrator to establish NSPS emission standards for new units that reflect the application of that BSER. In this case, the EPA proposes to determine that BSER is supercritical steam technology for large EGUs, and subcritical steam technology for small EGUs and coal refuse-fired EGUs. However, the Act prohibits the Administrator from expressly requiring sources to use any particular technology, such as supercritical steam conditions (*See* CAA section 111(b)(5), (h)). These provisions also ensure that NSPS standards do not preclude development of future technologies that may be even more efficient than the current supercritical systems. For new and reconstructed coal-fired boiler and IGCC EGUs, the EPA proposes to find that the best available steam conditions—which qualify as the BSER—support a standard of 1,900 lb CO_2/MWh-gross for large EGUs (*i.e.,* those with a nameplate heat input greater than 2,000 MMBtu/h), 2,000 lb CO_2/MWh-gross for small EGUs (*i.e.,* those with a nameplate heat input less

[101] The criteria pollutant coal-fired EGU NSPS subcategorizes coal refuse-fired EGUs in part due to the environmental benefits of remediating coal refuse piles.

than or equal 2,000 MMBtu/h), and 2,200 lb CO_2/MWh-gross for coal refuse-fired EGUs. Compliance with these standards would be determined on a 12-operating month rolling average basis. These levels of the standard are based on the emissions performance that can be achieved by a large pulverized or CFB coal-fired EGU using supercritical steam conditions and small and coal refuse-fired EGUs using subcritical steam conditions.

To determine what emission rates are currently achieved by existing coal-fired EGUs, the EPA reviewed annual generation and CO_2 emissions data from 2008 through 2017 for all coal-fired EGUs that submitted continuous emissions monitoring system (CEMS) data to the EPA's emissions collection and monitoring plan system (ECMPS). The data was sorted by the lowest maximum annual emissions rate for each unit to identify long term emission rates on a lb CO_2/MWh-gross basis that have been demonstrated by the existing coal fleet. Since an NSPS is a never-to-exceed standard, the EPA is proposing that long-term data are more appropriate than shorter term data to use in determining an achievable standard. These long-term averages account for degradation and variable operating conditions, and the EGUs should be able to maintain their current emission rates, as long as the units are properly maintained. While annual emission rates indicate a particular standard is achievable for certain EGUs in the short term, they are not necessarily representative of emission rates that can be maintained over an extended period using the most efficient available steam cycle (*i.e.,* the BSER), the range of fuel types that are burned, or all cooling systems.

Specifically, EGUs with the lowest annual emission rates use wet cooling systems and do not use dry cooling systems. Both recirculating cooling towers and once-through cooling systems require substantial amounts of water. In fact, the power sector is one of the largest freshwater consumers in the U.S.[102] Water usage by the power sector strongly depends on the generation technology. For example, combined cycle units use much less cooling water, because significantly less heat energy remains that is required to be removed by cooling at the outlet of the steam turbine of a combined cycle unit compared to a coal-fired EGU of the same capacity.

Dry cooling systems, however, may be necessary for a particular EGU due to limited water availability or desirable to eliminate the adverse environmental impacts caused by cooling tower intake structures. A drawback of dry cooling systems is that the EGU is unable to reach as low of a condensing temperature as with either a recirculating cooling tower or a once-through open system and is therefore less efficient. The EPA is aware of four existing coal-fired EGUs using a dry cooling system. Three are located in Wyoming, and one is located in Virginia. While the projects in Wyoming use this type of system in part or in whole due to the arid climate, the project in Virginia demonstrates that water use concerns are likely applicable to areas with larger amounts of rainfall as well. To further determine the likelihood that a developer of a new coal-fired EGU would want to use a dry cooling system, the EPA reviewed the cooling system of combined cycle units. More than 15 percent of operating natural gas-fired combined cycled capacity in the U.S. uses dry cooling technology.[103] Based on analysis of form EIA–860 data, these dry cooling systems are located throughout the U.S., further indicating that water use concerns are more widespread than just arid locations with limited rainfall. Therefore, the EPA is proposing that the NSPS for coal-fired EGUs should account for the use of dry cooling by setting higher emission rates that account for the lower efficiency of EGUs using dry cooling. The EPA is soliciting comment on whether it is appropriate to subcategorize based on geography and, if so, how that subcategorization should be done (Comment C–15). One potential approach would be to add a provision allowing the Administrator to approve alternate emissions standards for coal-fired EGUs located in areas without access to sufficient water to operate a cooling tower. Paragraph 60.4330(b) of the combustion turbine criteria pollutant NSPS (40 CFR part 60, subpart KKKK) includes a similar provision. That provision allows the Administrator to approve alternate SO_2 standards for a combustion turbine without access to natural gas and located in an area where removal of sulfur compounds would cause more environmental harm than good.

In order to determine the 12-operating month average emissions rate that is achievable by application of the BSER, the EPA analyzed data reported by owners/operators of EGUs to the CAMD database to identify the best performing (*i.e.,* the best operated and maintained) EGUs. The EPA normalized the emissions rate data to account for factors that the Agency has information on and that engineering equations can be used to account for design efficiency differences between EGUs based on the factors. The design factors include the steam cycle (*i.e.,* steam temperature and pressure and the number of reheat cycles), coal type (which impacts both boiler efficiency and emissions on a lb CO_2/MMBtu basis), cooling type (*i.e.,* dry, recirculating cooling tower, and open), and average ambient temperature. The EPA identified the single best EGU based on this normalized emissions rate. The EPA selected this single best unit to account for site specific factors about which the Agency does not have specific information. These factors include, but are not limited to, (1) design factors influencing efficiency (*e.g.,* number of feedwater heaters, economizer efficiency, combustion and soot blowing optimization, and an exposed structure or main building enclosure) and (2) O&M practices (*e.g.,* percent excess air, operator training, and prioritizing efficiency related repairs). The owner/operator of a new EGU would be able to incorporate the best EGU design parameters and O&M practices. The EPA then adjusted the emissions data for the best performing EGU by applying engineering equations for the EGU design factors (steam cycle, *etc.*) that impact the theoretical efficiency and the CO_2 emissions rate. For example, if a particular unit had no steam reheat cycle, the EPA estimated the theoretical increase in efficiency for a similar unit with a single reheat cycle.

Factors for which owners/operators have more limited influence include the condenser technology and ambient temperature. For example, designers can specify ultra-supercritical steam conditions compatible with state-of-the art metallurgy, multiple stages of feedwater heating, and double steam reheat cycles to optimize efficiency gains attributable to increasing the average temperature at which heat is supplied to the cycle. However, designers have fewer options for lowering the temperature at which heat is rejected from an affected EGU because this low-temperature constraint is largely determined by the available cooling reservoir and local ambient

[102] Water use in coal to Power Applications, available at *https://www.netl.doe.gov/research/Coal/energy-systems/gasification/gasifipedia/water-usage.*

[103] "Some U.S. electricity generating plants use dry cooling," *Today in Energy,* EIA, 29 August 2018, *https://www.eia.gov/todayinenergy/detail.php?id=36773.*

conditions. Consistent with the 2015 Rule, to account for the impact of ambient conditions, the EPA conservatively normalized the emission rate data to 20 °C, with one exception. Since coal refuse-fired EGUs are located in more temperate regions, the EPA assumed 10 °C for coal refuse-fired EGUs. In the 2015 rulemaking, the EPA assumed that a new large EGU would use some type of a wet cooling tower, but specifically accounted for air cooled condensers (*i.e.,* dry cooling) only for the small EGU subcategory. However, as described previously, the EPA is proposing to account for dry cooling for both large and small EGUs.

The EPA calculated 12-month CO_2 emission rates by dividing the sum of the CO_2 emissions by the sum of the gross electrical energy output over the same period. The best performing large EGU is Weston 4, which is a supercritical subbituminous-fired EGU located in Wisconsin, with an emissions rate of 1,780 lb CO_2/MWh-gross, measured over 12-operating months with 99-percent confidence. Based on the normalization of the Weston 4 data using various steam cycles and fuels, as well as dry cooling, the proposed emissions rate of 1,900 lb CO_2/MWh-gross is achievable for EGUs burning subbituminous, petroleum coke, and lignite using ultra-supercritical steam conditions and dry cooling. An EGU burning bituminous coal and dry cooling would be able to comply using supercritical steam conditions. Based on data submitted to ECMPS, 25 existing EGUs have maintained annual emission rates of 1,900 lb CO_2/MWh-gross over the past 10 years. While this includes a broad range of EGU types, it does not include any lignite-fired EGUs or coal-fired EGUs using dry cooling. The lowest emitting lignite-fired EGU is emitting at approximately 2,000 lb CO_2/MWh-gross, and the lowest emitting coal-fired EGU using dry cooling is emitting at approximately 2,100 lb CO_2/MWh-gross. However, no lignite-fired or coal-fired EGU using dry cooling is using ultra-supercritical steam conditions. The EPA has concluded that additional efficiency technologies could be incorporated into new units to allow a new EGU burning lignite with dry cooling to comply with the proposed standard.

The best performing small EGU is Wygen III, which is a subcritical subbituminous-fired EGU located in Wyoming, with a 12-operating month, 99-percent confidence emissions rate of 2,170 lb CO_2/MWh-gross. Wygen III has relatively low steam temperatures and pressures [104] and does not have a reheat cycle. Based on the normalization of the Wygen III data to the most efficient subcritical conditions and dry cooling,[105] the proposed 2,000 lb CO_2/MWh-gross emissions rate is achievable for any solid fuel other than coal refuse using the best available subcritical steam conditions and dry cooling. Based on data submitted to ECMPS, five small bituminous-fired EGUs have maintained a maximum annual emissions rate of 2,000 lb CO_2/MWh-gross over the reviewed 10-year period. These EGUs commenced operation between 1957 and 1960 and range in size from 1,400 MMBtu/h to 2,000 MMBtu/h. Four of these EGUs use once-through open cooling systems, and one uses a recirculating cooling tower for steam condensing. These long-term averages account for degradation and variable operating conditions and the EGUs should be able to maintain their current emission rates as long as the units are properly maintained. Normalization of the Wygen III data for a coal refuse-fired EGU indicates that a standard of 2,200 lb CO_2/MWh-gross is achievable for a coal refuse-fired EGU.

While the EPA is proposing these standards of performance, the Agency is also taking comment on a range of potential emission standards. Specifically, the EPA solicits comment on the following emission standard ranges:

• For new and reconstructed fossil fuel-fired steam generating units and IGCC units with a heat input rating that is greater than 2,000 MMBtu/h, a range of 1,700—1,900 lb CO_2/MWh-gross (Comment C–16);

• For new and reconstructed fossil fuel-fired steam generating units and IGCC units with a heat input rating of 2,000 MMBtu/h or less, a range of 1,800—2,000 lb CO_2/MWh-gross (Comment C–17);

• For new and reconstructed coal refuse-fired steam generating units and IGCC units, a range of 2,000–2,200 lb CO_2/MWh-gross (Comment C–18);

While some domestic coal-fired EGUs have maintained annual emission rates of 1,700 lb CO_2/MWh-gross, no existing coal-fired units have demonstrated multi-year performance at 1,700 lb CO_2/MWh-gross. Based on normalized Weston 4 data, this emissions rate could be met by a bituminous-fired EGU using supercritical steam conditions, a subbituminous-fired EGU using ultra-supercritical steam conditions, and petroleum coke and lignite-fired EGUs using the best available ultra-supercritical steam conditions and a cooling tower.[106] Three existing coal-fired EGUs have maintained a maximum annual emissions rate of 1,800 lb CO_2/MWh-gross over the reviewed 10-year period. These units include two supercritical bituminous-fired EGUs and one supercritical subbituminous-fired EGU. The EGUs commenced operation between 2008 and 2012 and range in size from 5,200 MMBtu/h to 7,900 MMBtu/h. All use recirculating cooling towers for condensing. Based on normalized Weston 4 data, an emission rate of 1,800 lb CO_2/MWh-gross is achievable for bituminous-fired EGUs using the best available subcritical steam condition; and subbituminous and dried lignite-fired EGUs using supercritical steam conditions when paired with a cooling tower.[107] An EGU burning undried lignite or petroleum coke could comply using ultra-supercritical steam conditions and a cooling tower.[108] However, a key assumption for achieving an 1,800 lb CO_2/MWh-gross emissions rate is the use of a cooling tower. With dry cooling, an 1,800 lb CO_2/MWh-gross emissions rate is only achievable for a bituminous-fired EGU using ultra-supercritical steam conditions. Based on normalized Weston 4 data, a 1,900 lb CO_2/MWh-gross emissions rate is achievable for bituminous-fired EGUs using the best available subcritical steam condition; and subbituminous, dried lignite, and petroleum coke-fired EGUs using supercritical steam conditions when paired with dry cooling. An EGU burning undried lignite could comply using ultra-supercritical steam conditions and dry cooling. The EPA proposes that a standard above 1,900 lb CO_2/MWh-gross for large units would not promote the use of the best available steam conditions.

For small EGUs, based on the normalization of the Wygen III emissions data, an emissions rate of 1,800 lb CO_2/MWh-gross is achievable for bituminous-fired EGUs using the best available subcritical steam conditions with either a cooling tower or dry cooling. In order to achieve this emissions rate, however, EGUs burning other solid fuels would be required to

[104] 11 MPa steam pressure and 541° C main steam temperature with no reheat cycle.

[105] The best available subcritical steam conditions are 21 MPa steam pressure and 570° C main and reheat steam temperature.

[106] Best available ultra-supercritical steam conditions are 650 °C (1,400 °F) and 36 MPa (5,000 psi).

[107] 24 MPa steam pressure and 593 °C main and reheat steam temperature (supercritical steam conditions).

[108] 30 MPa steam pressure and 600 °C main and 620 °C reheat steam temperature (ultra-supercritical steam conditions).

use additional compliance options such as co-firing natural gas, a hybrid power plant, integration of non-emitting generation technologies, or combined heat and power. Based on the normalization of the Wygen III emissions data, an emissions rate of 1,900 lb CO_2/MWh-gross could be met by any coal-fired EGU using the best available subcritical steam conditions and a cooling tower. However, only bituminous and subbituminous-fired EGUs could comply with this emissions rate using dry cooling. Without additional controls (*e.g.,* co-firing natural gas) EGUs burning dried lignite, petroleum coke, and undried lignite are only able to comply with an emissions rate of 2,000 lb CO2/MWh-gross using dry cooling. The EPA proposes that a standard above 2,000 lb CO_2/MWh-gross for small units would not appropriately promote the use of the best available efficiency technologies.

For all reconstructed EGUs, large and small, the EPA is soliciting comment on an emission standard consistent with the proposed standard for new small EGUs (*i.e.,* all reconstructed EGUs would have a standard of 2,000 lb CO_2/MWh-gross) (Comment C–19). While multiple organizations are evaluating repowering existing subcritical EGUs with supercritical topping cycles,[109] the EPA is only aware of a single EGU where this was actively considered—the Ferrybridge unit in the United Kingdom. The addition of a supercritical topping cycle is projected to reduce the heat rate for a large EGU by between 4 to 8 percent. While this would entail a substantial reduction in emissions, based on existing emissions data some large EGUs would still not be able to comply with an emissions rate of 1,900 lb CO_2/MWh-gross even with an 8 percent reduction in the emissions rate. For these units, additional efficiency improvements would also have to be conducted as part of the reconstruction project. The EPA is soliciting comment on whether a single standard regardless of size for reconstructed EGUs is appropriate and whether the existing reconstruction exemption in the general provisions (*i.e.,* a reconstructed EGU will be exempt from the requirement to meet the standard if the Administrator determines the standard is not technically or economically achievable (40 CFR 60.15(b)(2))) is sufficient to account for circumstances where a large reconstructed EGU would not be able to achieve the proposed emissions standard (Comment C–20).

F. Format of the Output-Based Standard

For all newly constructed units, the proposed standards are expressed on a gross output emission rate basis consistent with current monitoring and reporting requirements under 40 CFR part 75.[110] For a non-CHP EGU, gross output is the electricity generation measured at the generator terminals. In addition, the EPA is proposing equivalent net-output-based standards as a compliance alternative. Net output is the gross electrical output less the unit's total parasitic (*i.e.,* auxiliary) power requirements. A parasitic load for an EGU is a load or device powered by electricity, steam, hot water, or directly by the gross output of the EGU that does not contribute electrical, mechanical, or useful thermal output. In general, parasitic energy demands include less than 7.5 percent of non-IGCC and non-CCS coal-fired station power output and approximately 15 percent of non-CCS IGCC-based coal-fired station power output. Net output is used to recognize the environmental benefits of: (1) EGU designs and control equipment that use less auxiliary power; (2) fuels that require less emissions control equipment; and (3) higher efficiency motors, pumps, and fans. Thus, allowing compliance through net output would enable owners/operators of these types of units to pursue projects that reduce auxiliary loads for compliance purposes.

Owners/operators of utility boilers have multiple technology pathways available to comply with the actual emission standard, and the choice of both control technologies and fuel impact the overall auxiliary load. In the 2015 Rule, for utility boilers and IGCC units, the EPA finalized only gross-output-based standards. The rationale for not including an alternate net-output-based standard was that the Agency did not have sufficient information to establish an appropriate net-output-based standard that would not impact the identified BSER for these types of units. Therefore, the Agency could not identify an appropriate assumed auxiliary load to establish an equivalent net-output-based standard.

Since the proposed BSER determination has changed, the EPA is proposing CO_2 standards for steam generating units in a format similar to the 40 CFR part 60, subpart TTTT standards for combustion turbines and current EGU NSPS format for criteria pollutants. Thus, the proposed standards establish a gross-output-based standard. This allows owners/operators of new EGU to comply with the CO_2 emissions standard under Part 60 using the same data currently collected under Part 75.[111] However, in the 2015 Rule, many permitting authorities commented that the environmental benefits of using net-output-based standards can outweigh any additional complexities for particular units.[112] The EPA expects permitting authorities to continue to move toward net-output-based standards and have concluded that it is appropriate to support the expanded use of net-output-based standards. Therefore, the EPA is proposing to allow owners/operators of sources to elect between gross-output-based and net-output-based standards.

The EPA is proposing to use the current 40 CFR part 60, subpart TTTT procedures for requesting the use of the alternate net-output-based standard (40 CFR 60.5520(c)). Specifically, the owner/operator would be required to petition the Administrator in writing to comply with the alternate applicable net-output-based standard. If the Administrator grants the petition, this election would be binding and would be the unit's sole means of demonstrating compliance. Owners/operators complying with the net-output-based standard must similarly petition the Administrator to switch back to complying with the gross-output-based standard. This flexibility is particularly important for IGCC co-production (*i.e.,* to produce useful by-products and chemicals along with electricity) facilities. The implementing authority (*e.g.,* delegated state permitting authority) will best be able to identify the appropriate format for facilities of this type.

The EPA is not proposing to revise or reopening the 2015 Rule's (1) approach

[109] A supercritical topping cycle adds a new supercritical steam turbine that exhausts at the temperature, pressure, and flow of the existing steam turbine, allowing for reuse of existing infrastructure.

[110] 79 FR 1447–48.

[111] Additionally, having an NSPS standard that is measured using the same monitoring equipment as required under the operating permit minimizes compliance burden. If a combustion turbine were subject to both a gross and net emission limit, more expensive higher accuracy monitoring could be required for both measurements.

[112] In the 2015 rulemaking, the EPA solicited comment on a range of options for the form of the final standards. Many commenters supported gross-output-based standards, maintaining that a net-output standard penalizes the operation of air pollution control equipment and EGUs located in hot and/or dry areas of the country. Commenters further disagreed that a net-output standard provides any significant incentive to minimize auxiliary loads. Other commenters, however, maintained that the final rule should strictly require compliance on a net output-basis. They believed that this is the only way for the standards to minimize the carbon footprint of the electricity delivered to consumers. In general, both sets of commenters believed it appropriate to include net-output-based standards as an option in the final rule.

for determining the emissions rate for CHP units with useful thermal output that meet the applicability criteria or (2) expression of the standards in the form of limits on only emissions of CO_2, and not the other constituent gases of the air pollutant GHGs.[113]

VI. Rationale for Proposed Emission Standards for Modified Fossil Fuel-Fired Steam Generating Units

In CAA section 111(a)(4), a ''modification'' is defined as ''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. The EPA, through regulations, has determined that certain types of changes are exempt from consideration as a modification.[114] As discussed in the 2015 rulemaking, the EPA has historically been notified of only a limited number of NSPS modifications[115] involving fossil steam generating units and therefore predicted that few of these units would trigger the modification provisions and be subject to the final standards. Given the limited information that the Agency has about past modifications, the EPA concluded that it lacked sufficient information to establish standards of performance for all types of modifications at steam generating units. Instead, the EPA determined that it was appropriate to establish standards of performance for larger modifications, such as major facility upgrades involving, for example, the refurbishing or replacement of steam turbines and other equipment upgrades that could result in substantial increases in a unit's hourly CO_2 emissions rate. The Agency determined that it had adequate information regarding (1) the types of modifications that could result in large increases in hourly CO_2 emissions, (2) the types of measures available to control emissions from sources that undergo such modifications, and (3) the costs and effectiveness of such control measures, upon which to establish standards of performance for modifications with large emissions increases. The EPA concluded that the BSER for steam generating units that conduct modifications resulting in an hourly increase in CO_2 emissions (mass per hour) of more than 10 percent (''large'' modifications) was each affected unit's own best potential performance as determined by that unit's historical performance. The EPA deferred establishing standards for modified sources that conduct modifications resulting in an hourly increase in CO_2 emissions (mass per hour) of less than or equal to 10 percent (''small'' modifications). Therefore, sources that conduct small modifications did not fall within the definition of ''new source'' in section 111(a)(2) and continued to be an ''existing source'' as defined in section 111(a)(6).

In this proposal, the EPA is soliciting comment on a BSER and standard of performance for fossil fuel-fired steam generating EGUs that conduct small modifications. The BSER and associated standard of performance for which the EPA solicits comment are similar to the BSER and standard for fossil fuel-fired steam generating EGUs that conduct large modifications. To explain this solicitation of comment, it is convenient to refer to the 2015 Rule's discussion of the BSER and standard for large modifications (80 FR 64597–64600). However, the EPA is not proposing to revise or reopening the BSER or final standard for fossil fuel-fired steam generating EGUs that conduct large modifications (except that, as noted above, the EPA is proposing to revise the maximum stringency of the standard). The EPA is also not proposing standards of performance for fossil fuel-fired stationary combustion turbines that conduct modifications.

A. Identification of the BSER

The 2015 Rule provided that a steam generating EGU that undertook a large modification was required to meet a unit-specific CO_2 emission limit determined by that unit's best demonstrated historical performance (*i.e.,* the best annual performance during the years from 2002 to the time of the modification).[116] The EPA determined that this standard based on each unit's own best historical performance could be met through a combination of best operating practices and equipment upgrades and that these steps could be implemented cost effectively at the time when a source was undertaking a large modification. To account for facilities that had already implemented best practices and equipment upgrades, the final rule also specified that modified facilities did not have to meet an emission standard more stringent than the corresponding standard for reconstructed steam generating units.

In this action, the EPA is soliciting comment on a similar, but not identical, BSER and standard of performance for fossil fuel-fired steam generating EGUs that undertake small modifications (Comment C–21). The EPA believes that there are potentially different circumstances surrounding a small versus large modification. It seems highly unlikely that an owner or operator could inadvertently make a physical change in, or change in the method of operation of, a fossil fuel-fired steam-generating EGU that would result in an increase of hourly CO_2 emissions of more than 10 percent. As stated in the final 2015 Rule, such an increase in CO_2 emissions would likely come as a result of a significant capital investment in, or a significant change in the method of operation of, the affected EGU.

However, it is conceivable that an owner or operator could make a small physical change in, or change in the method of operation of, a fossil fuel-fired steam-generating EGU that results in an increase of hourly CO_2 emissions of less than 10 percent. If there is an applicable standard of performance for such ''small'' modifications, then the EGU could trigger the modification provisions and become a unit subject to federally-enforced CAA section 111(b) emission standards and, if the source had previously become subject to a CAA section 111(d) state program, it would no longer be subject to that program. The EPA solicits comment on the types of changes in operation or physical changes to a unit that could result in small increases in hourly CO_2 emissions (Comment C–22).

In this action, the Agency is seeking comment on the need for a standard for a small modification and, if needed, on the BSER and appropriate standard of performance (Comment C–23). As with the 2015 Rule's BSER for fossil fuel-fired EGUs conducting large modifications, the EPA solicits comment on identifying the BSER for such units conducting small modifications as also heat rate or efficiency improvements.

1. Reasonable Costs

Any efficiency improvement made by EGUs for the purpose of reducing CO_2 emissions will also reduce the amount of fuel that EGUs consume to produce the same electricity output. The cost attributable to CO_2 emission reductions, therefore, is the net cost of achieving

[113] As noted above, in the 2009 Endangerment Finding, EPA defined the relevant ''air pollution'' as the atmospheric mix of six long-lived and directly-emitted greenhouse gases: carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6). 74 FR 66497.

[114] 40 CFR 60.2, 60.14(e).

[115] NSPS modifications resulting in increases in hourly emissions of criteria pollutants.

[116] For the 2002 reporting year, EPA introduced new automated checks in the software that integrated automated quality assurance (QA) checks on the hourly data. Thus, EPA believes that the data from 2002 and forward are of higher quality.

heat rate improvements after any savings from reduced fuel expenses. The EPA estimates that, on average, the savings in fuel cost associated with heat rate improvements would be sufficient to cover much of the associated costs, and thus that the net costs of heat rate improvements associated with reducing CO_2 emissions from affected EGUs are relatively low.

The EPA recognizes that our cost analysis just described will characterize the costs for some EGUs more accurately than others because of differences in EGUs' individual circumstances. The EPA further recognize that reduced generation from coal-fired EGUs will tend to reduce the fuel savings associated with heat rate improvements, thereby raising the effective cost of achieving the CO_2 emission reductions from the heat rate improvements. Nevertheless, the EPA still expect that most of the investment required to capture the technical potential for CO_2 emission reductions from heat rate improvements would be offset by fuel savings, and that the net costs of implementing heat rate improvements as an approach to reducing CO_2 emissions from modified fossil fuel-fired EGUs are reasonable.

2. Reductions in CO_2 Emissions

This approach would achieve reasonable reductions in CO_2 emissions from the affected modified units as those units will be required to meet an emission standard that is consistent with more efficient operation. In light of the limited opportunities for emission reductions from retrofits, these reductions are adequate.

3. Technical Feasibility

A standard that is based on a site-specific, previously achieved emissions rate is technically feasible because there are a large number of available technologies and equipment upgrades, as well as best operating and maintenance practices, that EGU owners or operators may use to improve an EGU's efficiency.

4. Promotion of the Development and Implementation of Technology

As noted previously, the case law makes clear that the EPA is to consider the effect of its selection of the BSER on technological innovation or development, but that the EPA also has the authority to balance this factor against the various other factors (*See Sierra Club,* 657 F.2d at 346–47). With regard to the selection of emissions controls, modified sources face inherent constraints that newly constructed greenfield and reconstructed sources do not. As a result, modified sources present different, and in some ways more limited, opportunities for technological innovation or development. In this case, the standards promote technological development by promoting further development and market penetration of equipment upgrades and process changes that improve plant efficiency.

B. Determination of the Level of the Standard

An existing source that undergoes a modification should be able to at least match its best emission rate since 2002 because with the modification, it is expanding its capacity and therefore appears to be interested in upgrading and appears to believe that it will continue to operate for the long term. The EPA believes that any source that meets those conditions should be able to make whatever additional investment is necessary to assure that it meets its most efficient emission rate since 2002. Improving its efficiency in that manner should be consistent with its long-term operational goals. On the other hand, an existing source that is not undertaking that type of upgrade is differently situated. For example, it may not expect to operate over the long-term and it may have limited funds available for upgrades. Thus, it should be subject to the 111(d) rule's requirements, which assume that it can apply the EPA-identified heat rate improvement measures, but allow the state to determine whether all of those measures are appropriate, and further allow the state to grant a variance.

In the 2015 Rule, the final standard of performance for a steam generating unit implementing a large modification was a unit-specific emission limit based on that unit's own best one-year historical performance. The EPA determined that such a standard was achievable for a unit implementing a large (likely capital intensive and pre-planned) modification because the necessary upgrades could be implemented at the same time as the large modification. However, a unit that undertakes a small change may trigger the modification requirement, even without a large capital expenditure or coinciding with a pre-planned outage. The EPA solicits comment on the appropriate standard of performance for such EGUs (Comment C–24). In particular, the EPA solicits comment on whether the 2015 unit-specific emission limit is also appropriate for an EGU that conducts a small modification (Comment C–25).

To assess the potential heat rate improvement for existing coal-fired EGUs, the EPA looked at 11 years of historical gross heat rate data from 2007 to 2017 for 574 coal-fired EGUs that reported both heat input and gross electricity output to the Agency in 2017. The Agency used the 2007 to 2017 data to calculate several ''benchmark'' heat rates for each unit. This included calculating the 1-year average heat rate, the 2-year rolling average heat rate, and the 3-year rolling average heat rate. Within each of these groups, the EPA then selected the best (lowest) heat rate and fourth best heat rate. In all, the Agency calculated heat rate improvement potential using six different ''benchmarks'' (1-year best, 1-year fourth best, 2-year best, 2-year fourth best, 3-year best, and 3-year fourth best.). Within each category, each unit's ''benchmark'' heat rate has been used to calculate a gross electricity output weighted average across the unit population. The difference between the gross electricity output weighted average for a ''benchmark'' category and the 2017 gross electricity output weighted average (baseline) indicates the heat rate improvement potential. The heat rate improvement potential has been calculated nationally and at each regional interconnection: East, West, and Texas. Table 10 below shows the results expressed as a percent difference between the 2017 baseline heat rate and each ''benchmark.'' Nationally the range in heat rate improvement varies between 2 and 6.6 percent depending on which ''benchmark'' is used.

TABLE 10—POTENTIAL HEAT RATE IMPROVEMENT USING DIFFERENT BENCHMARKS

[Nationally and by regional interconnection]

Interconnect	2017 Heat rate (Btu/kWh [1])	Best one-year average (percent)	Fourth best one-year average (percent)	Best two-year rolling average (percent)	Fourth best two-year rolling average (percent)	Best three-year average (percent)	Fourth best three-year rolling average (percent)
National	9,849	6.6	2.9	5.4	2.4	4.6	2.0

TABLE 10—POTENTIAL HEAT RATE IMPROVEMENT USING DIFFERENT BENCHMARKS—Continued

[Nationally and by regional interconnection]

Interconnect	2017 Heat rate (Btu/kWh [1])	Best one-year average (percent)	Fourth best one-year average (percent)	Best two-year rolling average (percent)	Fourth best two-year rolling average (percent)	Best three-year average (percent)	Fourth best three-year rolling average (percent)
East	9,780	6.6	2.8	5.4	2.3	4.6	1.9
West	10,045	6.1	2.4	4.8	2.1	3.9	1.8
Texas	10,097	7.0	3.6	6.0	3.1	5.3	2.8

[1] Btu/kWh = British thermal units per kilowatt-hour.

The EPA solicits comment on which, if any, of these formulations should be used to determine the unit-specific standard of performance for a fossil fuel-fired steam generating unit that implements small modifications (Comment C–26). For example, should the EPA finalize a standard of performance that requires a steam generating unit that implements a small modification to meet an emission limit consistent with its best 1-year average emission or an emission limit consistent with its fourth best 2-year rolling average or some other emission limit? The EPA solicits comment on this approach and on any other methods to determine an appropriate unit-specific standard that takes into consideration the inherent differences in small modifications versus large modifications (Comment C–27).

VII. Interactions With Other EPA Programs and Rules

Nothing in this rulemaking changes the EPA's regulations or processes for determining whether a source is subject to permitting under the Prevention of Significant Deterioration (PSD) program or title V for its GHG emissions, nor does it require any additional revisions to State Implementation Plans for PSD applicability purposes or State title V Programs.

With respect to PSD, the CAA specifies that the best available control technology (BACT) cannot be less stringent than any applicable standard of performance under section 111. *Id.* Thus, in determining GHG BACT for a new EGU, if the EGU meets the applicability criteria of 40 CFR part 60, subpart TTTT, permitting authorities currently must consider the emission levels established under 40 CFR part 60, subpart TTTT as a controlling floor in the BACT review. If the EPA finalizes these proposed changes to 40 CFR part 60, subpart TTTT, permitting authorities will need to consider the amended 40 CFR part 60, subpart TTTT when determining the minimum level of GHG control that represents BACT for an affected EGU.

With respect to the title V operating permits program, this rule does not affect whether sources are subject to the requirement to obtain a title V operating permit. The 2015 rule included revisions to the fee requirements of the 40 CFR part 70 and part 71 operating permit rules under title V of the CAA to avoid inadvertent consequences for fees that would be triggered by the promulgation of the first CAA section 111 standard to regulate GHGs. In order to avoid excess fees from GHG emissions, the EPA revised the definition of regulated pollutant (for presumptive fee calculation) in 40 CFR 70.2 and regulated pollutant (for fee calculation) in 40 CFR 71.2 to exempt GHG emissions. This regulatory amendment had the effect of excluding GHG emissions from being subject to the statutory ($/ton) fee rate set for the presumptive minimum calculation requirement of part 70 and the fee calculation requirements of part 71. *See* 80 FR at 64632–64638; *Updated Guidance on EPA Review of Fee Schedules for Operating Permit Programs Under Title V,* Peter Tsirigotis, Director of the Office of Air Quality Planning and Standards, U.S. EPA, at 14–16 (Mar. 27, 2018). The EPA is not proposing to revise or reopening these provisions of the 2015 Rule, and nothing in this proposed rulemaking would require any additional changes to the title V regulations.

VIII. Summary of Cost, Environmental, and Economic Impacts

As discussed in the economic impact analysis accompanying this action, substantial new construction of coal-fired steam units is not anticipated under existing prevailing and anticipated future conditions. Therefore, the economic impact analysis concludes that this final rule will result in no or negligible costs overall on owners and operators of newly constructed EGUs during the 8-year NSPS review cycle (*See* CAA section 111(b)(1)(B)). This analysis reflects the best data available to the EPA at the time the modeling was conducted. As with any modeling of future projections, many of the inputs are uncertain. In this context, notable uncertainties, in the future, include the cost of fuels, the cost to operate existing power plants, the cost to construct and operate new power plants, infrastructure, demand, and policies affecting the electric power sector. The modeling conducted for this economic impact analysis is based on estimates of these variables, which were derived from the data currently available to the EPA. However, future realizations could deviate from these expectations as a result of changes in wholesale electricity markets, federal policy intervention, including mechanisms to incorporate value for onsite fuel storage, or substantial shifts in energy prices. The results presented in this economic impact analysis are not a prediction of what will happen, but rather a projection describing how this proposed regulatory action may affect electricity sector outcomes in the absence of unexpected shocks. The results of this economic impact analysis should be viewed in that context.

With regard to modified and reconstructed fossil fuel-fired steam generating units, this action proposes amended standards for reconstructed sources and the maximally stringent standard for modified sources. Historically, few EGUs have notified the EPA that they have modified under the modification provision of section 111(b), and similarly only one EGU, over the history of the NSPS program,[117] has notified the EPA that it has reconstructed. Moreover, approximately half of existing coal refuse-fired facilities are potentially exempt from this standard as CHP units. Based on this information, the EPA anticipates that few, if any, EGUs will take actions during the period of analysis that would be considered NSPS modifications or reconstruction and, as a result, be

[117] That is, from 1975, when EPA promulgated the regulations establishing the requirements for reconstructions, 40 FR 58420 (Dec. 16, 1975) (promulgating 40 CFR 60.15).

subject to the standards of performance proposed in this action.

A. What are the air impacts?

The EPA does not anticipate that this proposed rule will result in significant CO_2 emission changes by 2026. As explained immediately above, the EPA does not anticipate the construction of new coal-fired steam generating units and expects few, if any, coal-fired EGUs to trigger the proposed NSPS modification or reconstruction standard for these sources.

B. What are the energy impacts?

This proposed rule is not anticipated to have an effect on the supply, distribution, or use of energy. As previously stated, the EPA projects few, at most, new reconstructed or modified EGUs.

C. What are the compliance costs?

The EPA does not believe this proposed rule will have compliance costs associated with it, because, the EPA projects there to be, at most, few new, modified, or reconstructed fossil fuel-fired steam generating units that will trigger the provisions the EPA is proposing. The economic impact analysis includes an illustrative analysis of the potential project-level costs of this proposed action relative to the 2015 Rule's standards.

D. What are the economic and employment impacts?

The EPA does not anticipate that this proposed rule will result in economic or employment impacts because, the EPA projects there to be, at most, few new, modified, or reconstructed coal-fired steam generating units EGUs that will trigger the provisions the EPA is proposing. Likewise, the EPA believes this rule will not have any impacts on the price of electricity, employment or labor markets, or the U.S. economy.

E. What are the benefits of the proposed standards?

As previously stated, the EPA does not anticipate emission changes resulting from the rule as the EPA projects there to be, at most, few new, modified, or reconstructed coal-fired steam generating units that will trigger the provisions the EPA is proposing. Therefore, there are no direct climate or human health benefits associated with this rulemaking.

IX. Request for Comments

The EPA requests comments on all aspects of the proposed rulemaking, including the economic impact analysis (Comment C–28). All significant comments received will be considered in the development and selection of the final rule. The EPA is specifically soliciting comments on alternate compliance options (Comment C–29).

A. Subcategorization by Fuel Type

Except for coal refuse, the EPA is not proposing subcategorization by fuel type, but the Agency is soliciting comments on that approach (Comment C–30). The EPA is not proposing to subcategorize by fuel type for multiple reasons. Subcategorizing by fuel type could have the perverse impact of both increasing emissions and decreasing compliance options. Due to averaging, if the subcategorization is based on the fuel with the highest percentage heat input, owner/operators could have an incentive to burn sufficient amounts of higher emitting fuels in order to qualify for the higher emissions standard. For example, a facility that blends subbituminous and lignite would have a regulatory incentive to burn higher amounts of lignite than subbituminous coal (even though coal is lower emitting) in order to have a less stringent NSPS emissions rate. If the standard is determined based on the actual percentage of each fuel burned, that would limit the ability of owners/operators of coal-fired EGUs to use natural gas or other lower emitting fuels as compliance options because the emissions standard would become more stringent with increasing percentages of natural gas use. Both of these subcategorization by fuel type approaches fail to recognize the environmental benefit of lower emitting (*e.g.,* cleaner) fuels or integrated non-emitting (*i.e.,* renewable) electric generation. The proposed fuel neutral standard is consistent with the emissions standards in the criteria pollutant NSPS and is achievable for all coal types. This approach both incentivizes the use of lower emitting fuels and allows the use of natural gas and/or integrated renewable generation as compliance options.

B. Low Duty Cycle Subcategory

Due to the low variable operating costs of highly efficient coal-fired EGUs, any affected coal-fired EGU would likely operate at high capacity factors. This is confirmed by review of the hourly operating data from highly efficient coal-fired EGUs. As existing coal-fired generation EGUs retire and additional energy storage technologies enter the market, the EPA expects the remaining coal-fired EGUs to continue to operate at high loads. However, during periods of low electric demand, coal-fired EGUs may reduce load to approximately 45 percent as an alternate to shutting down completely. While efficiency is reduced at this load, it is high enough to maintain power generation, continue operation of the pollution control equipment, and allow the unit to ramp up relatively quickly as demand increases. Based on this, the EPA is soliciting comment on establishing separate emissions standards for steam generating units operating at partial load (Comment C–31).

Based on the data reviewed, maximum coal-fired EGU efficiency tends to be achieved when the EGU operates at between 80 to 90 percent load. Efficiency is relatively stable down to about 65 percent load [118] and up to 100 percent load. EGUs operating above or below those load levels experience noticeable reductions in efficiency. Due to maintenance concerns, EGUs would not operate above 100 percent of the rated load for extended periods of time. Also, brief periods of lower efficiencies will not have an appreciable impact on a 12-operating month rolling average emissions rate, so the Agency is not proposing to establish a subcategory for operation above 100 percent load. However, coal-fired EGUs operating at low loads (below approximately 65 percent) lose efficiency and could have difficulty in complying with an emissions standard that reflects the efficiencies achieved at higher operating loads unless they co-fire natural gas. Therefore, the EPA is soliciting comment on whether it would be appropriate to establish a subcategory for steam generating units during 12-month rolling average periods when the unit is not operated at high capacity factors (Comment C–32). Specifically, the Agency is considering a subcategory for units that operate at less than a 65 percent duty cycle on a rolling average basis during any 12-operating month period. Duty cycle is defined as the average operating load. It is different from capacity factor in that periods of no operation are not considered when calculating the duty cycle. The EPA is considering using duty cycle instead of capacity factor for several reasons. First, a standard based on capacity factor is more difficult to establish since it is a less precise measurement. A unit operating at a 65 percent capacity factor could either be operated at a constant 65 percent load or at 100 percent load 65 percent of the time and not operate for 35 percent of the time. For identical

[118] Sliding pressure steam generating units are able to maintain efficiency at part-load operation better then constant pressure steam generating units.

units, these operating profiles could result in substantially different emission rates. A duty cycle subcategorization approach assures that units are not deemed to be in the low load subcategory because of periods of non-operation. Specifically, the EPA is considering that during periods when these units are operated as non-base load units (12-operating month average duty cycle is less than 65 percent) an alternate emission standard would apply. The emission standards the EPA is soliciting comment on during non-base load operation for the subcategorized sources are 2,100 lb CO_2/MWh-gross for sources with a nameplate heat input rating of greater than 2,000 MMBtu/h, 2,200 lb CO_2/MWh-gross for sources with a heat input rating of less than or equal to 2,000 MMBtu/h, and 2,400 lb CO_2/MWh-gross for coal refuse-fired steam generating units (Comment C–33).[119]

The EPA is also soliciting comment on establishing a part load heat input-based standard (similar to the part load standard for combustion turbines) as an alternate or in place of the low duty cycle output-based standard (Comment C–34). The advantage of a heat input-based standard is that it is a constant value based on the fuel burned and is independent of efficiency and provides a clear compliance option regardless of the level of degradation of efficiency that results from operation at low loads. However, this approach does not directly recognize the environmental benefit of efficient operation at part load. To incorporate recognition of the environmental benefit of energy efficiency into the heat input-based standard, the EPA proposes to conclude that it is not appropriate to base a heat input standard on the emissions rate of bituminous coal (the lowest emitting coal on a heat input basis). While compliance would be straight forward for bituminous-fired EGUs and would only require a small amount of co-firing for units burning other coals, basing a heat input standard on the emissions rate of bituminous coal would not recognize the environmental benefit of efficient part load operation. This could have the perverse environmental impact of increasing emissions. Owners and operators of EGUs that are expected to dispatch at part loads would have limited regulatory incentive to assure that the unit is operated efficiently. In fact, there would be a regulatory incentive to operate the unit at lower duty cycles specifically to qualify for the part load standard.

Based on this, the EPA solicits comment on whether only a more stringent heat input-based standard would be appropriate (Comment C–35). The alternate heat input-based standard the EPA is considering would be based on the heat input-based emissions rate of 200 lb CO_2/MMBtu. This approach has the advantage of allowing for a clear path for continuous compliance, while at the same time recognizing the environmental benefit of efficient operation across all load levels. Due to the price of natural gas relative to coal, owner/operators of EGUs would have a financial incentive to operate their units as efficiently as possible so they could comply with the full load standard with as low an average duty cycle as possible (*i.e.,* below 65 percent) without co-firing natural gas and/or fuel oil. Less efficient EGUs operating below a 65 percent duty cycle, and well maintained efficient EGUs operating at substantially lower duty cycles or idle conditions, could co-fire approximately 15 percent natural gas to demonstrate compliance. The EPA is soliciting comment on whether this is a reasonable requirement (Comment C–36). Specifically, as traditionally coal-fired EGUs shift from base load use towards being reserved for capacity requirements (*e.g.,* peaking units) natural gas often becomes the primary fuel due to the ability to reduce expenses from operation of post-combustion emissions control equipment.

The EPA is also soliciting comment on several related issues. First, the Agency soliciting comment on the cutoff point for the low duty cycle standard (Comment C–37). The EPA is currently considering a range of between 50 to 70 percent average duty cycle. In addition, the EPA is soliciting comment on whether the low duty cycle subcategory should be based on percent of potential electric sales instead of a heat input-based capacity factor (Comment C–38). While this approach is similar to a heat input-based capacity factor approach, it would use the same calculational procedure as for combustion turbines. The primary difference is that EGUs that generate power for use on site (*e.g.,* combined heat and power units) would not be subject to the output-based standard as frequently. Finally, the EPA is soliciting comment on whether IGCC units should also have a low duty cycle subcategory or if a single standard should apply at all load levels (Comment C–39). IGCC units are particularly well suited to burn natural gas efficiently and co-firing would allow compliance at all load levels.

C. Commercial Demonstration Permit

The steam generating unit criteria pollutant NSPS (subpart Da) includes a provision to assure that NSPS requirements do not discourage the development and implementation of innovative and emerging technologies. Specifically, the commercial demonstration permit (40 CFR 60.47Da) provides a procedure for owner/operators of new coal-fired EGUs proposing to demonstrate an emerging technology to apply to the Administrator for a slightly less stringent standard than would otherwise be required. The commercial demonstration permit section of the EGU criteria pollutant NSPS was included in the original 1979 rulemaking (44 FR 33580) and was later updated in the 2012 amendments (77 FR 9304) to assure that the NSPS recognizes the environmental benefit of the development of new and emerging technologies. The rationale for this provision includes that the innovative technology waiver under section 111(j) of the CAA does not by itself offer adequate support for certain capital-intensive technologies, as it does not provide sufficient time for amortization (44 FR 33580). The authority to issue these permits is predicated on the D.C. Circuit Court's opinion in *Essex Chemical Corp.* v. *Ruckelshaus,* 486 F. 2d 42 (D.C. Cir. 1973); NSPS should be set to avoid unreasonable costs or other impacts. Similar provisions for emerging technologies are included in the industrial-commercial-institutional steam generating unit criteria pollutant NSPS (52 FR 47839).

Standards requiring a high level of performance, such as the proposed standards for GHG emissions, might discourage the continued development of some new technologies. The EPA recognizes that owners/operators in the utility sector may not accept the risk of using new and innovative technologies as the emission reduction efficiencies of such technologies have not been fully demonstrated. As such, owners/operators may prefer conventional, demonstrated technologies. Therefore, it is desirable that standards of performance accommodate and foster the continued development of emerging technologies. Special provisions may be needed to encourage the continued development and use of technologies that show promise in achieving levels of performance comparable or superior to those achieved by the use of fully demonstrated conventional technologies, but at reduced cost or with

[119] Based on review of hourly emissions data, part load emission rates are approximately 10 percent higher than the minimum full load emissions rate. To maintain the minimum full load emissions rate, a unit would have to co-fire approximately 20 percent natural gas when operating at part load.

other offsetting environmental or energy benefits. Establishing less stringent percent reduction requirements for emerging technologies may substantially reduce financial risk and increases the likelihood that owners and operators of new coal-fired EGUs will install and operate emerging technologies. The experience gained in utilizing emerging technologies will, in turn, foster their continued development. Unlike most other air pollutants, GHG pollution has limited direct health impacts and can persist in the atmosphere for decades or millennia, depending on the specific GHG. This special characteristic makes transfer of control technologies and long-term technology innovation particularly important factors when considering appropriate control options for GHG emissions.

To mitigate the potential negative impact on emerging technologies, the EPA is soliciting comment on whether it should include a commercial demonstration permit provision in 40 CFR part 60, subpart TTTT (Comment C–40). The EPA believes that this provision would encourage the development of new technologies and compensate for problems that may arise when applying them to commercial-scale units. The technologies the EPA is currently considering include pressurized fluidized bed technology, alternate power cycle working fluid (*e.g.,* supercritical CO_2), additional energy recovery using integrated thermo-electric materials, a supercritical CO_2 Brayton cycle, an integrated organic rankine cycle, integrated hybrid photovoltaic-solar thermal, integrated novel energy storage technologies, and novel carbon capture technologies. Specifically, the Administrator (in consultation with DOE) would issue commercial demonstration permits for the first 1,000 MW of full-scale demonstration units of each emerging technology. Owners/operators of the units that are granted a commercial demonstration permit would be exempt from the otherwise applicable standards of subpart TTTT and would instead be subject to less stringent emission standards. To encourage the continued development of emerging technologies, standards should be set low enough to be reasonably attainable, but stringent enough to ensure a minimum level of CO_2 emissions to protect human health and the environment. Although there is some uncertainty on setting a precise standard, the standards the EPA is considering would be 100 lb CO_2/MWh higher than the proposed standards for new and reconstructed units using conventional technologies. The proposed commercial demonstration permit standards would provide flexibility for innovative and emerging technologies and ensure the NSPS does not preclude the development of these technologies while at the same time maintaining the emission standards for traditional control technologies. The EPA is also soliciting comment on whether other innovative emerging technologies should be included (Comment C–41). Specifically, the Agency is interested in commenters' views with regard to other innovative boiler designs, new materials that would allow for the use of advanced ultra-supercritical steam conditions, supercritical topping cycles, and alternate cooling technologies.

The EPA selected these particular technologies for the following reasons. Pressurized fluidized bed technology combines a pressurized circulating fluidized bed boiler with a combustion turbine. This combination essentially creates a coal-fired combined cycle power plant and has the potential to improve the efficiency and reduce the environmental impact (on both a criteria pollutant and GHG emissions basis) of using coal to generate electricity. However, it is still a relatively developing technology and has only been deployed on a limited basis worldwide. Traditional coal-fired power plants use water as the working fluid in a rankine cycle. Water is heated to create steam that is then expanded through a steam turbine to generate electricity. The use of alternate working fluids, such as supercritical CO_2, has the potential to increase the efficiency of converting thermal energy to electricity. However, these systems have not yet been fully demonstrated.

Coal-fired power plants generate significant quantities of relatively low-temperature heat (*i.e.,* waste heat) that cannot be used by the traditional rankine cycle. This heat is currently sent to the power plant cooling system (*e.g.,* cooling tower). If this energy could be recovered to produce additional electricity, it could significantly reduce the environmental impact of power generation. Thermoelectric materials are materials that generate electricity due to temperature differences across the material. Organic rankine cycle use working fluids with boiler points lower than that of water and can generate electricity from lower temperature sources of heat. Both of these technologies have the potential to recover useful energy from the waste heat from power plants, but neither has been fully demonstrated.

Hybrid power plants combined multiple forms of power generation in a single integrated system. The integration of solar thermal with traditional fossil fuel-fired power plants has been demonstrated at multiple facilities. A promising technology that could expand the opportunities for additional hybrid fossil fuel-fired EGUs is the integration of hybrid photovoltaic-solar thermal. Hybrid photovoltaic-solar thermal first concentrates the solar energy onto photovoltaic cells that convert a portion of that energy directly into electricity. As a result of the concentrated solar energy, the photovoltaic cells are heated, and additional useful thermal output energy is recovered from the ''hot'' photovoltaic cells. This approach is potentially more efficient than either standalone photovoltaic or solar thermal EGUs. The recovered thermal energy from hybrid photovoltaic-solar thermal is relatively low and has limited potential for direct integration into the thermal cycle. However, it could potentially be integrated into coal-fired power plants for boiler feedwater heating or the generation of low pressure steam. However, the integration of hybrid photovoltaic-solar thermal power has not been demonstrated on a fossil fuel-fired EGU, so the efficiency gains cannot be estimated. A developer of a new coal-fired EGU would therefore be unable to rely on this technology to guarantee compliance with the NSPS until the technology is further developed.

At the utility level, energy storage devices have historically provided improved power quality (*i.e.,* frequency and voltage) and help to manage the amount of power required to supply (*i.e.,* generation) and load (*i.e.,* customers demand) during periods of peak power demand. With the advent of increasing amounts of variable generation energy storage technology can help integrate renewable energy efficiently into the electric grid. Since renewable generation generally provides electricity based on local conditions (*e.g.,* when the wind is blowing or the sun is shining) and is not dispatched by grid operators to satisfy demand, large amounts of renewable generation can result in excess power generation (*i.e.,* grid oversupply) that results in dispatchable generators operating in a non-optimal manner and decreasing operating efficiency. Low-cost energy storage technologies with high electricity-in to electricity-out round-trip efficiency [120] could help to balance load and generation allowing for the integration of additional renewable

[120] Round-trip efficiency is the ratio of the energy recovered from the energy storage device and the energy put into the device.

generation while maintaining a dependable power supply and allowing for the operation of dispatchable power plants at peak operating efficiencies. A high round trip efficiency is necessary to assure that the losses in the energy storage technology are less than the increase in emissions that would result from operating the dispatchable fossil fuel-fired EGUs under conditions that result in lower operating efficiencies.

Utility scale energy storage systems are classified into mechanical, electrochemical, chemical, electrical, and thermal energy storage systems. While some of these technologies are well demonstrated (*e.g.,* pumped storage), other novel technologies are still in development. A developer installing a novel energy storage device to allow the EGU to operate at closer to maximum efficiency would not be able to guarantee the cycle efficiency or reliability of the energy storage technology and would therefore not be able to rely on the integration for compliance purposes. Demonstrating innovative energy storage technologies could help address barriers reducing costs and accelerating market acceptance.

An owner or operator of a new or reconstructed coal-fired EGU who wished to demonstrate a novel carbon capture technology could face multiple difficulties in demonstrating continuous compliance. First, novel carbon capture technologies by nature prevent quantitative assessment of their continuous performance. If the capture system were taken down for repair or modification, the entire facility might have to be taken off line to assure continuous compliance. In addition, due to the additional auxiliary load and increased stack emissions per MWh of electricity generated, the captured CO_2 would need to be sequestered for the unit to demonstrate continuous compliance. Sequestering relatively small amounts of CO_2 could be technically challenging and cost prohibitive, therefore limiting the development of more cost-effective capture technologies. Without the commercial demonstration permit provision, it would be difficult for an owner/operator of a coal-fired EGU to support a CCS demonstration project while still maintaining compliance with the NSPS emissions standard.

Allowing the Administrator to approve commercial demonstration permits would limit regulatory impediments to improvements in GHG reduction technologies. If the Administrator finds (in consultation with DOE) that a given emerging technology (taking into consideration all areas of environmental impact, including air, water, solid waste, toxics, and land use) offers superior overall environmental performance, permission to operate in compliance with alternative standards could then be granted by the Administrator. A mere modification of an existing demonstrated technology will not be viewed as emerging technologies and will not be approved for a commercial demonstration permit. The EPA is requesting comment on additional technologies that should be considered, as well as the maximum magnitude of the demonstration permits (Comment C–42). In particular, the Agency is considering including DOE demonstration projects as emerging technologies and potential candidates for the commercial demonstration permit. This would assure that the NSPS would continue to accommodate alternate technologies as they become available.

D. Applicability to Industrial EGUs

In simple terms, the current applicability provisions require that an EGU be capable of combusting over 250 MMBtu/h of fossil fuel and be capable of selling 25 MW to a utility distribution system in order to be subject to 40 CFR part 60, subpart TTTT. These applicability provisions exclude industrial EGUs. However, since the affected EGU includes ''integrated equipment that provides electricity or useful thermal output,'' certain large processes might be included as part of the EGU and meet the applicability criteria. For example, the high-temperature exhaust from an industrial process (*e.g.,* calcining kilns, dryer, or metals processing) that consumes fossil fuel could be sent to a heat recovery steam generator. If the industrial process is over 250 MMBtu/h heat input and the electric sales exceed the applicability criteria, then the unit could be subject to 40 CFR part 60, subpart TTTT. This is potentially problematic for multiple reasons. First, it is difficult to determine the useful output of the EGU since part of the useful output is included in the industrial process. In addition, the fossil fuel that is combusted might have a relatively high CO_2 emissions rate on a lb/MMBtu basis, making it problematic to meet the emissions standard. Finally, the compliance costs associated with 40 CFR part 60, subpart TTTT could discourage the development of environmentally beneficial projects.

To avoid these outcomes, the EPA is soliciting comment on amendments to the applicability provisions (Comment C–43). One option the Agency considering is amending the provisions to include an industrial unit exemption (Comment C–44). This exemption would apply to any EGU where greater than 50 percent of the heat input is derived from an industrial process that does not produce any electrical or mechanical output or useful thermal output that is used outside the affected EGU. In addition, the EPA soliciting comment on excluding fuels that are combusted to comply with another EPA regulation (*e.g.,* control of HAP emissions) from being considered a fossil fuel (Comment C–45).

The current approach owner/operators of CHP units use to calculate net-electric sales and net energy output includes that ''at least 20.0 percent of the total gross or net energy output consists of electric or direct mechanical output.'' It is unlikely that a CHP with a relatively low electric output (*i.e.,* less than 20 percent) would meet the applicability criteria. However, if a CHP unit with less than 20 percent of the total output consisting of electricity were to meet the applicability criteria, the net-electric sales and net energy output would be calculated the same as for a traditional non-CHP EGU. Even so, it is not clear that these CHP units would have less environmental benefit per unit of electricity produced than more traditional CHP units. The EPA is therefore soliciting comment on eliminating the restriction that CHP produce at least 20 percent electrical or mechanical output to qualify for the CHP specific method for calculating net-electric sales and net energy output (Comment C–46).

The current electric sales applicability exemption for non-CHP steam generating units includes the provision that steam generating units have ''*always been subject to a federally enforceable permit* limiting annual net electric sales to one-third or less of their potential electric output (*e.g.,* limiting hours of operation to less than 2,920 hours annually) or limiting annual electric sales to 219,000 MWh or less'' (emphasis added). The justification for this restriction includes that the 40 CFR part 60 subpart Da applicability language includes ''constructed for the purpose of . . .'' and the Agency concluded that the intent was defined by permit conditions (80 FR 64544). This applicability criterion is important for determining applicability with both the new source section 111(b) requirements and if existing steam generating units are subject to the existing source section 111(d) requirements. For steam generating units that commenced construction after September 18, 1978, the applicability date of 40 CFR part 60 subpart Da, applicability would be relatively clear by what criteria pollutant NSPS is applicable to the facility. However, for steam generating units that commenced construction prior to September 18, 1978 or where the owner/operator determined that criteria pollutant NSPS applicability was not critical to the project (*e.g.,* emission controls were sufficient to comply with either the EGU or industrial boiler criteria pollutant NSPS) owners/operators might not have requested an electric sales permit restriction be included in the operating permit. Under the current applicability language, some onsite steam generating unit electric generators could be covered by the existing source section 111(d) requirements even if they have never sold electricity to the grid. The EPA is soliciting comment on amending the electric sales exemption to read have ''*have never sold more than one-third of their potential electric output or 219,000 MWh, whichever is greater, and are* ~~always been~~ subject to a federally enforceable permit limiting annual net electric sales to one-third or less of their potential electric output (*e.g.,* limiting hours of operation to less than 2,920 hours annually) or limiting annual electric sales to 219,000 MWh or less'' (emphasis added) (Comment C–47). EGUs that reduce current generation would continue to be covered as long as they sold more than ⅓ of their potential electric output at some time in the past.

E. Non-Sequestration of Captured Carbon

While carbon capture technology is not included in the proposed BSER, the EPA recognizes that there are potential site-specific situations where a developer elects to install carbon capture technology. For example, a developer might wish to evaluate a particular capture technology or to sell the captured CO_2. However, 40 CFR part 60, subpart TTTT as currently written requires that captured CO_2 be geologically sequestered or stored in a different manner that is as effective as geologic sequestration. Captured CO_2 that is sold to the food industry would not currently qualify for emission reduction because it results in near term releases rather than in permanent sequestration. However, a different situation can be envisioned in which the captured CO_2 could be considered to offset CO_2 generated specifically for the food industry and from a life cycle perspective it would be as effective as sequestration at reducing emissions. Therefore, to accommodate non geologic sequestration and to support the effective utilization and management of CO_2, the EPA is soliciting comment on amending the second sentence of paragraph 60.555(g) to read ''To receive a waiver, the applicant must demonstrate to the Administrator that its technology will store captured CO_2 as effectively as geologic sequestration *or the CO_2 will be used as an input to an industrial process where the life cycle emissions are reducing emissions as effective as geologic sequestration,* and that the proposed technology will not cause or contribute to an unreasonable risk to public health, welfare, or safety.'' (emphasis added) (Comment C–48)

F. Additional Amendments

The EPA is soliciting comment on multiple less significant amendments. These amendments either would be either strictly editorial and would not change any of the requirements of subpart TTTT or are intended to add additional compliance flexibility. For additional information on these amendments, see the regulatory text track changes technical support document. First, the EPA is considering editorial amendments to define acronyms the first time they are used in the regulatory text (Comment C–49). Second, the EPA is considering adding International System of Units (SI) equivalent for owners/operators of stationary combustion turbines complying with a heat input-based standard (Comment C–50). Third, the EPA is considering fixing errors in the current subpart TTTT regulatory text referring to part 63 instead of part 60 (Comment C–51). Fourth, as a practical matter owners/operators of stationary combustion turbines subject to the heat input-based emissions standard need to maintain records of electric sales to demonstrate that they are not subject to the output-based emissions standard. Therefore, the EPA is soliciting comment on adding specific requirement that owner/operators maintain records of electric sales to demonstrate they did not sell electricity above the threshold that would trigger the output-based standard (Comment C–52). Next, the EPA is soliciting comment on if the ANSI, ASME, and ASTM test methods should be updated to include more recent versions of the test methods (Comment C–53). Finally, the EPA is soliciting comment on adding additional compliance flexibilities for EGUs either serving a common electric generator or using a common stack (Comment C–54). Specifically, for EGUs serving a common electric generator should the Administrator be able to approve alternate methods for determining energy output? For EGUs using a common stack, the EPA is soliciting comment on if specific procedures should be added for apportioning the emissions and/or if the Administrator should be able to approve site specific alternate procedures.

G. Non-Base Load Combustion Turbines

As noted in the General Information section above, in the 2015 Rule, the EPA set separate standards for base load and non-base load stationary combustion turbines. The electric sales threshold between the two subcategories is based on the design efficiency of the combustion turbine. Stationary combustion turbines qualify as non-base load, and thus for a less stringent standard of performance, if they have net electric sales equal to or below their design efficiency (not to exceed 50 percent) multiplied by their potential electric output, 80 FR at 64,601 (*e.g.,* a 40 percent efficient combustion turbine can sell up to 40 percent of its potential electrical output), but if their sales exceed that level, they are treated as base load and subject to a more stringent standard of performance. For additional discussion on this approach, *see* the 2015 Rule (80 FR 64609 to 64612).

Recently, stakeholders have expressed concerns about this approach for distinguishing between base load and non-base load turbines. They posit a scenario under which increased utilization of wind and solar resources, combined with low natural gas prices, would result in certain types of simple cycle turbines being deemed attractive to operate for a longer period of time than had been contemplated at the time the 2015 Rule was being developed. Specifically, stakeholders have observed that in some regional electricity markets with large amounts of wind generation, some of the most efficient new simple cycle turbines—aeroderivative turbines—could be called on to operate at capacity factors greater than their design efficiency; however, if they were to be operated at those higher capacity factors, they would become subject to the more stringent standard of performance for base load turbines, which they would not be able to meet. As a result, according to these stakeholders, the owners or operators of the aeroderivative turbines would have to curtail their generation and less efficient turbines would be called on to run, which would result in higher emissions.

Although, as noted above, the EPA is not re-opening the standards promulgated in the 2015 Rule for combustion turbines, the EPA is soliciting comment on the concerns identified by stakeholders to determine the extent of the potential issue identified above and, if necessary, potential remedies. Specifically, the EPA is soliciting information, including seeking supporting data and documentation, on whether there have been, or are anticipated to be, circumstances (*e.g.,* high utilization of wind or solar resources or low natural gas prices) in which simple cycle stationary combustion aeroderivative turbines (*i.e.,* those that are subject to standards of performance in 40 CFR part 60 subpart TTTT) have been or may be called upon to operate in excess of the non-base load threshold described in the 2015 Rule (Comment C–55). The EPA is also requesting information on whether, and the extent to which, these aeroderivative turbines are different in design and operation than frame simple cycle turbines and NGCC units, including fast start NGCC units (Comment C–56). The EPA is also requesting information on the environmental consequences, if any, of the aeroderivative combustion turbines having to forego continued operation in such circumstances (*e.g.,* is a more efficient turbine being displaced by a higher emitting turbine or utility boiler?) (Comment C–57). The EPA is also soliciting comment on remedies that the Agency should consider, if necessary, to address this potential concern. For example, should the EPA consider creating a separate subcategory and standard of performance for simple cycle aeroderivative turbines? Should the EPA consider changing the formula used to calculate allowable operating hours for non-baseload combustion turbines? Should the Agency consider creating a process by which owners or operators could petition the EPA to increase the allowable operating hours for non-baseload combustion turbines on a case-by-case basis if they could demonstrate that, given the composition of the regional grid they belong to, the increase would result in better overall environmental outcome? (Comment C–58). The EPA will evaluate all comments and any new information and, if warranted, will initiate a subsequent rulemaking to address any issues raised from this solicitation of comment.

X. Statutory and Executive Order Reviews

Additional information about these statutes and Executive Orders can be found at *https://www.epa.gov/laws-regulations/laws-and-executive-orders.*

A. Executive Order 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review

This action is a significant regulatory action that was submitted to the Office of Management and Budget (OMB) for review. Any changes made in response to OMB recommendations have been documented in the docket. The EPA prepared an economic impact analysis of the potential costs and benefits associated with this action. This analysis is contained in the *Economic Impact Analysis for the Review of Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units.* The economic impact analysis includes an illustrative analysis of the potential difference in project-level costs of constructing a coal-fired EGU under this proposed standard relative to the 2015 standard.

B. Executive Order 13771: Reducing Regulation and Controlling Regulatory Costs

This action is expected to be an Executive Order 13771 regulatory action. There are no quantified cost estimates for this proposed rule because the EPA does not anticipate this action to result in costs or cost savings. For more information on this conclusion please see the *Economic Impact Analysis for the Review of Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units.*

C. Paperwork Reduction Act (PRA)

This action does not impose any new information collection burden under the provisions of the PRA. The information required by the rule is already collected and reported by other regulatory programs. OMB has previously approved the information collection activities contained in the existing 40 CFR part 75 and 98 regulations and has assigned OMB control numbers 2060–0626 and 2060–0629, respectively.

D. Regulatory Flexibility Act (RFA)

I certify that this action will not have a significant economic impact on a substantial number of small entities under the RFA. In making this determination, the impact of concern is any significant adverse economic impact on small entities. An agency mat certify that a rule will not have a significant economic impact on a substantial number of small entities if the rule relieves regulatory burden, has no net burden, or otherwise has a positive economic effect on the small entities subject to the rule. The EPA does not project any new, modified, or reconstructed coal-fired electric utility steam generating units. As such, this proposed rule would not impose significant requirements on those sources, including any that are owned by small entities. The EPA has, therefore, concluded that this action will have no net regulatory burden for all directly regulated small entities.

E. Unfunded Mandates Reform Act (UMRA)

This action does not contain an unfunded mandate of $100 million or more as described in UMRA, 2 U.S.C. 1531–1538, and does not significantly or uniquely affect small governments. This action is not expected to impact state, local, or tribal governments.

F. Executive Order 13132: Federalism

This action does not have federalism implications. It would not have substantial direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government.

G. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

This action does not have tribal implications, as specified in Executive Order 13175. It would neither impose substantial direct compliance costs on tribal governments, nor preempt Tribal law. The EPA is aware of three coal-fired EGUs located in Indian Country, but is not aware of any EGUs owned or operated by tribal entities. The EPA notes that this action would only affect existing sources such as the three coal-fired EGUs located in Indian Country, if those EGUs were to take actions constituting modifications or reconstructions as defined under the EPA's NSPS regulations. However, as previously stated, the EPA does not project any new, reconstructed, or modified EGUs. Thus, Executive Order 13175 does not apply to this action.

The EPA will hold meetings with tribal environmental staff during the public comment period to inform them of the content of this proposal and will offer further consultation with tribal elected officials where it is appropriate. The EPA specifically solicits additional comment from tribal officials on this proposed rule.

H. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks

The EPA interprets Executive Order 13045 as applying only to those regulatory actions that concern health or safety risks that the EPA has reason to believe may disproportionately affect children, per the definition of "covered regulatory action" in section 2–202 of the Executive Order. This action is not subject to Executive Order 13045 because it does not concern an environmental health or safety risk.

I. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use

This action is not a "significant energy action" because it is not likely to have a significant adverse effect on the supply, distribution, or use of energy. This proposed action is not anticipated to have impacts on emissions, costs, or energy supply decisions for the affected electric utility industry.

J. National Technology Transfer and Advancement Act (NTTAA)

This action involves technical standards. Therefore, the EPA conducted a search to identify potentially applicable voluntary consensus standards (VCS). However, the Agency identified no such standards. Therefore, the EPA has decided to continue to use technical standard Method 19 of 40 CFR part 60, appendix A. The EPA invites the public to identify potentially applicable VCS and to explain why such standards should be used in this action (Comment C–59).

K. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations

The EPA believes that this action does not have disproportionately high and adverse human health or environmental effects on minority populations, low-income populations, and/or indigenous peoples, as specific in Executive Order 12898 (59 FR 7629, February 16, 1994), because it does not affect the level of protection provided to human health or the environment. As previously stated, the EPA does not project any fossil fuel-fired electric utility steam generating units would be affected by this action.

XI. 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 in 40 CFR Part 60

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

Dated: December 6, 2018.

Andrew R. Wheeler,

Acting Administrator.

For the reasons set out in the preamble, title 40, chapter I, part 60 of the Code of Federal Regulations is proposed to be 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.*

Subpart TTTT—[Amended]

■ 2. Section 60.5509 is amended by revising paragraph (b)(2) to read as follows:

§ 60.5509 Am I subject to this subpart?

* * * * *

(b) * * *

(2) Your EGU is capable of deriving 50 percent or more of the heat input from non-fossil fuel at the base load rating 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. Section 60.5520 is amended by revising paragraphs (a) and (c) to read as follows:

§ 60.5520 What CO_2 emissions 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, 2, or 3 of this subpart, consistent with paragraphs (b), (c), and (d) of this section, as applicable.

* * * * *

(c) As an alternate to meeting the requirements in paragraph (b) of this section, an owner or operator of an EGU 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.

* * * * *

■ 4. Section 60.5525 is amended by revising the introductory text, the introductory text of paragraph (c), and paragraphs (c)(1)(i) and (ii), (c)(2), and (c)(3) to read as follows:

§ 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, 2, or 3 of this subpart for the applicable CO_2 emission standards.

* * * * *

(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, 2, or 3 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) * * *

(i) Section 60.5555(c)(3)(i), for units subject to the Acid Rain Program; or

(ii) Section 60.5555(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 § 60.5555(c)(3)(i) (for Acid Rain program units), or according to § 60.5555(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 § 60.5555(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 § 60.5555(c)(3)(iii).

■ 5. Section 60.5535 is amended by revising paragraphs (f) and (g) to read as follows:

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

* * * * *

(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, 2, or 3 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, 2, or 3 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.

■ 6. Section 60.5540 is amended by revising the introductory text of paragraph (a) and paragraph (b) to read as follows:

§ 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, 2, or 3 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.

* * * * *

(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, 2, or 3 of this part, or the emissions standard calculated in accordance with § 60.5525(a)(2).

■ 7. Section 60.5555 is amended by revising paragraph (a)(2)(v) to read as follows:

§ 60.5555 What reports must I submit and when?

(a) * * *

(2) * * *

(v) Consistent with § 60.5520, the CO_2 emissions standard (as identified in Table 1, 2, or 3 of this part) with which your affected EGU must comply; and

* * * * *

■ 8. Section 60.5560 is amended by revising paragraph (f) to read as follows:

§ 60.5560 What records must I maintain?

* * * * *

(f) You must keep records of the calculations you performed to assess compliance with each applicable CO_2 mass emissions standard in Table 1, 2, or 3 of this subpart.

* * * * *

■ 9. Section 60.5580 is amended by revising the definitions for ''Base load rating'' and ''Design efficiency,'' revising paragraph (2) of the definition for ''Net-electric sales,'' and revising the definition for ''Violation'' to read as follows:

§ 60.5580 What definitions apply to this subpart?

* * * * *

Base load rating means the maximum amount of heat input (fuel) that an EGU can combust on a steady state basis plus the maximum amount of heat input derived from non-combustion source (*e.g.,* solar thermal), 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.

* * * * *

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), ISO 2314 Gas turbines—acceptance tests (incorporated by reference, see § 60.17), or an alternative approved by the Administrator.

* * * * *

Net-electric sales means: * * *

(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 the

applicable percentage of purchased power of the thermal host facility or facilities. The applicable percentage of purchase power for CHP facilities is determined based on the percentage of the total thermal load of the host facility supplied to the host facility by the CHP facility. For example, if a CHP facility serves 50 percent of a thermal hosts thermal demand, the owner/operator of the CHP facility would subtract 50 percent of the thermal hosts electric purchased power when determining net-electric sales.

* * * * *

Violation means a specified averaging period over which the CO_2 emissions rate is higher than the applicable emissions standard located in Table 1, 2, or 3 of this subpart.

■ 10. Re-designate Table 3 of Subpart TTTT of Part 60 as Table 4 of Subpart TTTT of Part 60.

■ 11. Revise the heading of Table 1 of Subpart TTTT of Part 60 to read as follows:

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, but Before December 21, 2018, and Reconstruction or Modification After June 18, 2014, but Before December 21, 2018

[**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]

* * * * *

■ 12. Add new Table 3 of Subpart TTTT of Part 60 to read as follows:

Table 3 of Subpart TTTT of Part 60—CO_2 Emission Standards for Affected Steam Generating Units and Integrated Gasification Combined Cycle Facilities That Commenced Construction, Reconstruction, or Modification After December 21, 2018 (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 and reconstructed steam generating unit or IGCC that has base load rating of 2,100 GJ/h (2,000 MMBtu/h) or less.	910 kg CO_2/MWh (2,000 lb CO_2/MWh) of gross energy output; or 980 kg CO_2/MWh (2,160 lb CO_2/MWh) of net energy output.
Newly constructed and reconstructed steam generating unit or IGCC that has base load rating greater than 2,100 GJ/h (2,000 MMBtu/h).	870 kg CO_2/MWh (1,900 lb CO_2/MWh) of gross energy output; or 940 kg CO_2/MWh (2,070 lb CO_2/MWh) of net energy output.
Newly constructed and reconstructed steam generating unit or IGCC units that burn 75 percent or more (by heat input) coal refuse on a 12-operating month rolling average basis.	1,000 kg CO_2/MWh (2,200 lb CO_2/MWh) of gross energy output; or 1,080 kg CO_2/MWh (2,380 lb CO_2/MWh) of net energy output.
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 more stringent than: 1. 910 kg CO_2/MWh (2,000 lb CO_2/MWh) of gross energy output; or 980 kg CO_2/MWh (2,160 lb CO_2/MWh) of net energy output for units with a base load rating of 2,100 GJ/h (2,000 MMBtu/h) or less; or 2. 870 kg CO_2/MWh (1,900 lb CO_2/MWh) of gross energy output; or 940 kg CO_2/MWh (2,070 lb CO_2/MWh) of net energy output for units with a base load rating of greater than 2,100 GJ/h (2,000 MMBtu/h); or 3. 1,000 kg CO_2/MWh (2,200 lb CO_2/MWh) of gross energy output; or 1,080 kg CO_2/MWh (2,380 lb CO_2/MWh) of net energy output for units that burn 75 percent or more (by heat input) coal refuse on a 12-operating month rolling average basis.

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