Per Bob’s earlier e-mail, here is the mods preamble language. Per our brief discussion, we plan to send some additional language Tuesday addressing some things we have heard about the new source proposal that are relevant here.

<< EO12866_GHG EGU ModifiedSources 2060-AR88 Proposal__20140523 to OMB.docx >>
CARBON POLLUTION STANDARDS FOR MODIFIED AND RECONSTRUCTED POWER PLANTS: STANDARDS OF PERFORMANCE FOR GREENHOUSE GAS EMISSIONS FROM MODIFIED AND RECONSTRUCTED STATIONARY SOURCES: ELECTRIC UTILITY GENERATING UNITS

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: In this action, the Environmental Protection Agency (EPA) is proposing standards of performance for emissions of greenhouse gases from affected modified and reconstructed fossil fuel-fired electric utility steam generating units and natural gas-fired stationary combustion turbines that supply more than one-third of their potential electric output to the grid. Natural gas-fired combustion turbines that operate as peaking units, those that operate at supply one-third or less of their maximum capacity potential to the grid, are not covered by today’s proposal. With respect to affected modified fossil fuel-fired electric utility steam generating units (utility boilers and integrated gasification combined cycle units), the EPA is co-proposing two alternatives related...
standards of performance. For Under the first alternative, all modified units would be subject to a single standard of performance. In the second co-proposed alternative, the EPA is proposing that the specific form of the standard will depend on whether the source makes the modification before or after becoming subject to a CAA section 111(d) plan. This alternative recognizes that actions taken to comply with a Clean Air Act (CAA) section 111(d) plan may result in improved performance at the source. In all cases the level of the proposed standards is based on a combination of best operating practices and equipment upgrades.

For affected modified natural gas-fired stationary combustion turbines, the agency is proposing standards of performance set at a level based on efficient Natural Gas Combined Cycle (NGCC) technology. These standards would be applicable whether or not a unit is subject to a section 111(d) plan.

For affected reconstructed fossil fuel-fired electric utility steam generating units (utility boilers and integrated gasification combined cycle units), and for affected reconstructed natural gas-fired stationary combustion turbines, the EPA is proposing standards of performance based on the most efficient generating technology that is applicable to each...
category of units. This standard would not be affected by the submittal of a CAA section 111(d) plan.

DATES: Comments on the proposed standards. Comments on the proposed standards must be received on or before [INSERT DATE 60 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER].

Comments on the information collection request. Under the Paperwork Reduction Act (PRA), since the Office of Management and Budget (OMB) is required to make a decision concerning the information collection request between 30 and 60 days after [INSERT DATE OF PUBLICATION IN THE FEDERAL REGISTER], a comment to the OMB is best assured of having its full effect if the OMB receives it by [INSERT DATE 30 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER].

Public Hearing. In a separate action in the Federal Register, the EPA is proposing Clean Air Act (CAA) section 111(d) emission guidelines for existing fossil fuel-fired electric utility generating units (EGUs) and is announcing public hearings associated with that action. Because of the interconnected nature of this proposed rulemaking with the proposed Emission Guidelines for Existing Sources, we will hold joint hearings on both proposed rulemakings. Please consult the Federal Register notice proposing Emission Guidelines for Existing Sources for information on public hearings for both actions the proposed emission guidelines and for this action.

Comment [A4]: … proposing Emission Guidelines for Existing Sources?
EPA Response: Fixed
Additionally, information for the joint public hearings will be posted on the following website: [http://www2.epa.gov/carbon-pollution-standards/](http://www2.epa.gov/carbon-pollution-standards/). If any dates, times or locations of announced public hearings are changed for the proposed emission guidelines, then the public hearing dates, times and locations for this action will also change accordingly. If you would like to speak at the public hearing(s), please register by following instructions provided in the notice for the emission guidelines proposed in the Federal Register. Please note that written statements and supporting information submitted during the comment period will be considered with the same weight as oral comments and supporting information presented at the public hearing.

**ADDRESSES:** Comments. Submit your comments, identified by Docket ID No. EPA-HQ-OAR-2013-0603, by one of the following methods:

At the website [http://www.regulations.gov](http://www.regulations.gov): Follow the instructions for submitting comments.

At the website [http://www.epa.gov/oar/docket.html](http://www.epa.gov/oar/docket.html): Follow the instructions for submitting comments on the EPA Air and Radiation Docket website.

Email: Send your comments by electronic mail (email) to a-and-r-docket@epa.gov, Attn: Docket ID No. EPA-HQ-OAR-2013-0603.

Facsimile: Fax your comments to (202)566-9744, Attn: Docket ID No. EPA-HQ-OAR-2013-0603.
Mail: Send your comments to the EPA Docket Center, U.S. EPA, Mail Code 28221T, 1200 Pennsylvania Ave., NW, Washington, DC 20460, Attn: Docket ID No. EPA-HQ-OAR-2013-0603. In addition, please mail a copy of your comments on the information collection provisions should be mailed to the Office of Information and Regulatory Affairs, OMB, Attn: Desk Officer for EPA, 725 17th St. NW, Washington, DC 20503.

Hand Delivery or Courier: Deliver your comments to the EPA Docket Center, William Jefferson Clinton Building West, Room 3334, 1301 Constitution Ave., NW, Washington, DC 20004, Attn: Docket ID No. EPA-HQ-OAR-2013-0603. Such deliveries are accepted only during the Docket Center’s normal hours of operation (8:30 a.m. to 4:30 p.m., Monday through Friday, excluding Federal holidays), and special arrangements should be made for deliveries of boxed information.

Instructions: All submissions must include the agency name and docket ID number (EPA-HQ-OAR-2013-0603). The EPA’s policy is to include all comments received without change, including any personal information provided, in the public docket, available online at http://www.regulations.gov, unless the comment includes information claimed to be confidential business information (CBI) or other information whose disclosure is restricted by statute. Do not submit information that you consider to be CBI or otherwise protected through
http://www.regulations.gov or email. Send or deliver information identified as CBI only to the following address: Roberto Morales, OAQPS Document Control Officer (C404-02), Office of Air Quality Planning and Standards, U.S. EPA, Research Triangle Park, North Carolina 27711, Attention Docket ID No. EPA-HQ-OAR-2013-0603. Clearly mark the part or all of the information that you claim to be CBI. For CBI information on a disk or CD-ROM that you mail to the EPA, mark the outside of the disk or CD-ROM as CBI and then identify electronically within the disk or CD-ROM the specific information you claim as CBI. In addition to one complete version of the comment that includes information claimed as CBI, you must submit a copy of the comment that does not contain the information claimed as CBI for inclusion in the public docket. Information so marked will not be disclosed except in accordance with procedures set forth in 40 CFR part 2.

The EPA requests that you also submit a separate copy of your comments to the contact person identified below (see FOR FURTHER INFORMATION CONTACT). If the comment includes information you consider to be CBI or otherwise protected, you should send a copy of the comment that does not contain the information claimed as CBI or otherwise protected.

The www.regulations.gov website is an “anonymous access” system, 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 http://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 disk or CD-ROM 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 avoid the use of special characters, any form of encryption and be free of any defects or viruses.

Docket: All documents in the docket are listed in the http://www.regulations.gov index. Although listed in the index, some information is not publicly available (e.g., CBI or other information whose disclosure is restricted by statute). Certain other material, such as copyrighted material, will be publicly available only in hard copy. Publicly available docket materials are available either electronically at http://www.regulations.gov or in hard copy at the EPA Docket Center, William Jefferson Clinton Building West, Room 3334, 1301 Constitution Ave., NW, Washington, DC. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding federal holidays. The telephone number for the Public
Reading Room is (202)566-1744, and the telephone number for the Air Docket is (202)566-1742. Visit the EPA Docket Center homepage at http://www.epa.gov/epahome/dockets.htm for additional information about the EPA’s public docket.

In addition to being available in the docket, an electronic copy of this proposed rule will be available on the World Wide Web (WWW) through the technology transfer network (TTN). Following signature, a copy of this proposed rule will be posted on the TTN’s policy and guidance page for newly proposed or promulgated rules at the following address: http://www.epa.gov/ttn/oarpg/.

FOR FURTHER INFORMATION CONTACT: Mr. Christian Fellner, Energy Strategies Group, Sector Policies and Programs Division (D243-01), U.S. EPA, Research Triangle Park, NC 27711; telephone number (919)541-4003, facsimile number (919)541-5450; email address: fellner.christian@epa.gov or Dr. Nick Hutson, Energy Strategies Group, Sector Policies and Programs Division (D243-01), U.S. EPA, Research Triangle Park, NC 27711; telephone number (919)541-2968, facsimile number (919)541-5450; email address: hutson.nick@epa.gov.

SUPPLEMENTARY INFORMATION: Acronyms. A number of acronyms and chemical symbols are used in this preamble. While this may not be an exhaustive list, to ease the reading of this preamble and for reference purposes, the following terms and acronyms are
defined as follows:

<table>
<thead>
<tr>
<th>Acronym</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>AEO</td>
<td>Annual Energy Outlook</td>
</tr>
<tr>
<td>APPA</td>
<td>American Public Power Association</td>
</tr>
<tr>
<td>BSER</td>
<td>Best System of Emission Reduction</td>
</tr>
<tr>
<td>CAA</td>
<td>Clean Air Act</td>
</tr>
<tr>
<td>CAP</td>
<td>Climate Action Plan</td>
</tr>
<tr>
<td>CBI</td>
<td>Confidential Business Information</td>
</tr>
<tr>
<td>CCS</td>
<td>Carbon Capture and Storage (or Sequestration)</td>
</tr>
<tr>
<td>CFB</td>
<td>Circulating Fluidized Bed</td>
</tr>
<tr>
<td>CH₄</td>
<td>Methane</td>
</tr>
<tr>
<td>CHP</td>
<td>Combined Heat and Power</td>
</tr>
<tr>
<td>CO₂</td>
<td>Carbon Dioxide</td>
</tr>
<tr>
<td>DCE</td>
<td>Direct Contact Evaporator</td>
</tr>
<tr>
<td>DOE</td>
<td>Department of Energy</td>
</tr>
<tr>
<td>EGU</td>
<td>Electric Utility Generating Unit</td>
</tr>
<tr>
<td>EO</td>
<td>Executive Order</td>
</tr>
<tr>
<td>EPA</td>
<td>Environmental Protection Agency</td>
</tr>
<tr>
<td>FB</td>
<td>Fluidized Bed</td>
</tr>
<tr>
<td>FR</td>
<td>Federal Register</td>
</tr>
<tr>
<td>GHG</td>
<td>Greenhouse Gas</td>
</tr>
<tr>
<td>HFC</td>
<td>Hydrofluorocarbon</td>
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<tr>
<td>HRSG</td>
<td>Heat Recovery Steam Generator</td>
</tr>
<tr>
<td>ICR</td>
<td>Information Collection Request</td>
</tr>
<tr>
<td>IGCC</td>
<td>Integrated Gasification Combined Cycle</td>
</tr>
<tr>
<td>IPCC</td>
<td>Intergovernmental Panel on Climate Change</td>
</tr>
<tr>
<td>lb CO₂/MWh</td>
<td>Pounds of CO₂ per Megawatt-hour</td>
</tr>
<tr>
<td>lb CO₂/MWh-net</td>
<td>Pounds of CO₂ per megawatt-hour on a net output basis</td>
</tr>
<tr>
<td>LCOE</td>
<td>Levelized Cost of Electricity</td>
</tr>
<tr>
<td>MMBtu/h</td>
<td>Million British Thermal Units per Hour</td>
</tr>
<tr>
<td>MPa</td>
<td>Megapascal</td>
</tr>
<tr>
<td>MW</td>
<td>Megawatt</td>
</tr>
<tr>
<td>MWe</td>
<td>Megawatt Electrical</td>
</tr>
<tr>
<td>MWh</td>
<td>Megawatt-hour</td>
</tr>
<tr>
<td>N₂</td>
<td>Nitrogen Gas</td>
</tr>
<tr>
<td>N₂O</td>
<td>Nitrous Oxide</td>
</tr>
<tr>
<td>NOx</td>
<td>Nitrogen Oxide</td>
</tr>
<tr>
<td>NAICS</td>
<td>North American Industry Classification System</td>
</tr>
<tr>
<td>NDCE</td>
<td>Non-Direct Contact Evaporator</td>
</tr>
<tr>
<td>NETL</td>
<td>National Energy Technology Laboratory</td>
</tr>
<tr>
<td>NGCC</td>
<td>Natural Gas Combined Cycle</td>
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<tr>
<td>NGR</td>
<td>Natural Gas Reburning</td>
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<tr>
<td>NRC</td>
<td>National Research Council</td>
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<tr>
<td>NRECA</td>
<td>National Rural Electric Cooperative Association</td>
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<tr>
<td>NSPS</td>
<td>New Source Performance Standards</td>
</tr>
<tr>
<td>NTTAA</td>
<td>National Technology Transfer and Advancement Act</td>
</tr>
</tbody>
</table>
Organization of This Document. The information presented in this preamble is organized as follows:

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   C. Does this action apply to me?

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   B. GHG Emissions from Fossil Fuel-fired EGUs
   C. The Utility Power Sector
   D. Statutory Background
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   F. Stakeholder Outreach

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   B. Emission Standards
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   E. Emissions Performance Testing Requirements
   F. Continuous Compliance Requirements
   G. Notification, Recordkeeping and Reporting Requirements
IV. Rationale for Reliance on Rational Basis to Regulate GHG from Fossil Fuel-fired EGU
A. Rational Basis and Endangerment Finding
B. Source Categories

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VI. Rationale for Emission Standards for Reconstructed Fossil Fuel-Fired Utility Boilers and IGCC Units
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B. Identification of Best System of Emissions Reduction
C. Determination of the Level of the Standard
D. Compliance Period

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A. Introduction
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C. Determination of the Level of the Standard
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VIII. Rationale for Emission Standards for Reconstructed Natural Gas-fired Stationary Combustion Turbines
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B. Determination of the Standards of Performance

IX. Rationale for Emission Standards for Modified Natural Gas-fired Stationary Combustion Turbines
A. Identification of the Best System of Emission Reduction
B. Determination of the Level of the Standards of Performance

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B. What are the energy impacts?
C. What are the compliance costs?
D. How will this proposal contribute to climate change protection?
E. What are the economic and employment impacts?
F. What are the benefits of the proposed standards?

XI. Statutory and Executive Order Reviews
A. Executive Order 12866, Regulatory Planning and Review, and Executive Order 13563, Improving Regulation and Regulatory Review
B. Paperwork Reduction Act
C. Regulatory Flexibility Act
D. Unfunded Mandates Reform Act
E. Executive Order 13132, Federalism
F. Executive Order 13175, Consultation and Coordination With Indian Tribal Governments
G. Executive Order 13045, Protection of Children From Environmental Health Risks and Safety Risks
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I. General Information

A. Executive Summary

1. Purpose of the Regulatory Action

   On June 25, 2013, in conjunction with announcement of his Climate Action Plan (CAP), President Obama issued a Presidential Memorandum directing the EPA to issue a new proposal to address carbon pollution from new power plants by September 30, 2013 and to issue “standards, regulations, or guidelines, as appropriate, which address carbon pollution from modified, reconstructed and existing power plants.” Consistent with the Presidential Memorandum, on September 20, 2013, the Administrator signed proposed carbon pollution standards for newly constructed fossil fuel-fired power plants (79 FR 1430, January 8, 2014) (January 2014 proposal). Specifically, under the authority of Clean Air Act (CAA) section 111(b), the EPA proposed new source performance standards (NSPS) to limit emissions of carbon dioxide (CO₂) from newly constructed fossil fuel-fired electric utility steam generating units (utility boilers and integrated gasification combined cycle (IGCC) units) and newly constructed natural gas-fired stationary combustion turbines.
In this action, under the authority of CAA section 111(b), the EPA is proposing standards of performance to limit emissions of CO₂ from modified and reconstructed fossil fuel-fired electric utility steam generating units and natural gas-fired stationary combustion turbines, as well as from reconstructed fossil fuel-fired electric utility steam generating units and natural gas-fired stationary combustion turbines. Specifically, the EPA is proposing standards of performance for: (1) modified fossil fuel-fired utility boilers and IGCC units, (2) modified natural gas-fired stationary combustion turbines, (3) reconstructed fossil fuel-fired utility boilers and IGCC units, and (4) reconstructed natural gas-fired stationary combustion turbines. Consistent with the requirements of CAA section 111(b), these proposed standards reflect the degree of emission limitation achievable through the application of the best system of emission reduction (BSER) that the EPA has determined has been adequately demonstrated for each type of unit.

In a separate action, under CAA section 111(d), the EPA is proposing emission guidelines for states to use in developing plans to limit CO₂ emissions from existing fossil fuel-fired EGUs. States must then submit plans to the EPA under timing set by that action.


The proposed standards for the affected modified and
reconstructed sources are summarized below in Table 1.

Table 1. Summary of BSER and Proposed Standards for Affected Sources

<table>
<thead>
<tr>
<th>Affected Source</th>
<th>BSER</th>
<th>Standard</th>
</tr>
</thead>
<tbody>
<tr>
<td>Modified Utility Boilers and IGCC Units</td>
<td>Most efficient generation at the affected source achievable through a combination of best operating practices and equipment upgrades</td>
<td>Co-proposed Alternative #1</td>
</tr>
<tr>
<td></td>
<td></td>
<td>1. Source would be required to meet a unit-specific emission limit determined by the unit’s best historical annual CO₂ emission rate (from 2002 to the date of the modification) plus an additional two percent emission reduction; the emission limit will be no lower than:</td>
</tr>
<tr>
<td></td>
<td></td>
<td>a. 1,900 lb CO₂/MWh-net for sources with heat input &gt; 2,000 MMBtu/h.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>OR</td>
</tr>
<tr>
<td></td>
<td></td>
<td>b. 2,100 lb CO₂/MWh-net for sources with heat input ≤ 2,000 MMBtu/h.</td>
</tr>
</tbody>
</table>

Modified Utility Boilers and IGCC Units | Most efficient generation at the affected source achievable through a combination of best operating practices and equipment upgrades | Co-proposed Alternative #2 |
| | | Source would be required to meet a unit-specific emission limit dependent upon when the modification occurs. |
| | | 1. Sources that modify prior to becoming subject to a CAA 111(d) plan would be required to meet a unit-specific emission limit determined by the unit’s best historical annual CO₂ emission rate (from 2002 to date of the modification) plus an additional two percent emission reduction; the emission limit will be no lower than: |
| | | a. 1,900 lb CO₂/MWh-net for sources with heat input > 2,000 MMBtu/h. |
| | | OR |
| | | b. 2,100 lb CO₂/MWh-net for sources with heat input ≤ 2,000 MMBtu/h. |
2,000 MMBtu/h.

2. Sources that modify after becoming subject to a CAA 111(d) plan would be required to meet a unit-specific emission limit determined by the 111(b) permitting implementing authority from the results of an energy efficiency improvement audit.

<table>
<thead>
<tr>
<th>Modified Natural Gas-Fired Stationary Combustion Turbines</th>
<th>Efficient NGCC technology</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Sources with heat input &gt; 850 MMBtu/h would be required to meet an emission limit of 1,000 lb CO₂/MWh-gross.</td>
<td></td>
</tr>
<tr>
<td>2. Sources with heat input ≤ 850 MMBtu/h would be required to meet an emission limit of 1,100 lb CO₂/MWh-gross.</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Reconstructed Utility Boilers and IGCC Units</th>
<th>Most efficient generating technology at the affected source</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Sources with heat input &gt; 2,000 MMBtu/h would be required to meet an emission limit of 1,900 lb CO₂/MWh-net.</td>
<td></td>
</tr>
<tr>
<td>2. Sources with heat input ≤ 2,000 MMBtu/h would be required to meet an emission limit of 2,100 lb CO₂/MWh-net.</td>
<td></td>
</tr>
</tbody>
</table>

<table>
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<tr>
<th>Reconstructed Natural Gas-Fired Stationary Combustion Turbines</th>
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<tr>
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<td></td>
</tr>
<tr>
<td>2. Sources with heat input ≤ 850 MMBtu/h would be required to meet an emission limit of 1,100 lb CO₂/MWh-gross.</td>
<td></td>
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</tbody>
</table>

**Note:** For the reasons discussed in the “Legal Memorandum1”

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1 The “Legal Memorandum” supporting document is available in the rulemaking docket for the proposed emission guidelines for existing source power plants, “Carbon Pollution Guidelines for Existing Power Plants: Emission Guidelines for Greenhouse Gas Emissions for Existing Stationary Sources,” and in a separate document, “Legal Memorandum.”
supporting document in the docket for the rulemaking for CO₂ emissions from existing EGUs under section 111(d)—, all existing sources that become modified or reconstructed sources and which are subject to a CAA section 111(d) plan at the time of the modification or reconstruction, will remain in the CAA section 111(d) plan and remain subject to any applicable regulatory requirements in the plan, in addition to being subject to regulatory requirements under CAA section 111(b).

It should be noted that the EPA intends each standard of performance proposed in this rulemaking to be severable from each other standard of performance, such that if one or more of the standards of performance were to be remanded or vacated in a court challenge, the EPA intends for the other standards to remain in effect. The EPA also intends each BSER determination or alternative determination, as applicable, for modified utility boilers and IGCC units, and for modified natural gas-fired stationary combustion turbines, to be severable from each other BSER determination. In all of these cases, the EPA believes that the standards of performance and associated best systems of emission reduction operate independently of each other.

Emissions from Existing Stationary Sources: Electric Utility Generating Units, Docket ID: EPA-HQ-OAR-2013-0602."
The EPA also intends that the standards applicable to the units that modify after the unit is subject to a 111(d) plan are severable and that if those standards were over-turned, the standards applicable to requirements for units that modify when they are not subject to a 111(d) plan would apply to all modified sources, regardless of the timing of their modification.

The EPA is proposing that the form of the standards for modified and reconstructed natural gas-fired stationary combustion turbines be consistent with the standards for newly constructed natural gas-fired stationary combustion turbines proposed on January 8, 2014 (79 FR 1430). In that proposal, the EPA proposed standards for turbines on a gross output basis, but also took comment on standards on a net output basis. The EPA is similarly proposing standards on a gross output basis, while soliciting comment on net output based standards, in today's proposal for modified and reconstructed natural gas-fired stationary combustion turbines. To the extent that the EPA finalizes modified and reconstructed standards for stationary combustion turbines that are consistent with the standards for

3 See K Mart Corp. v. Cartier, Inc., 486 U.S. 281, 294 (1988) (holding that a regulation was severable because the “[t]he severance and invalidation of [the subsection at issue would] not impair the function of the statute as a whole, and there [was] no indication that the regulation would not have been passed but for its inclusion.”).
newly constructed stationary combustion turbines, the EPA intends to take the same approach with regards to the use of net or gross output in both final actions.

3. Costs and Benefits

As explained in the regulatory impact analysis (RIA)\(^4\) for this proposed rule and further below, the EPA expects few, if any, units would trigger either the modification or the reconstruction provisions that we are proposing today. Because there have been a limited number of units that have notified the EPA of NSPS modifications in the past, we have conducted an illustrative analysis of the costs and benefits for a representative modified unit. Based on the analysis, which is presented in Chapter 9 of the RIA, the EPA projects that this proposed rule will result in potential CO\(_2\) emission changes, quantified benefits, and costs for a unit that is subject to the modification provision. In this illustrative example based on a hypothetical 500 MW coal-fired unit, we estimate costs, net of fuel savings, of $0.78 million to $4.5 million (2011$) and CO\(_2\) reductions of 133,000 to 266,000 tons in 2025. The climate benefits from reductions in CO\(_2\), combined with the health co-benefits from reductions in SO\(_2\), NO\(_x\), and PM\(_{2.5}\), total $18 to $33

\(^4\) The RIA for this proposal is presented as Chapter 9 of the RIA for the companion rulemaking for proposed Emission Guidelines for Greenhouse Gas Emissions from Existing Stationary Sources: Electric Utility Generating Units.
million (2011$) at a 3 percent discount rate for emission reductions in 2025 for the lowest emission reduction scenario, and $35 to $65 million ($2011) at a 3 percent discount rate for emission reductions in 2025 for the highest emission reduction scenario.  

B. Overview

1. What authority is the EPA relying on to address power plant CO₂ emissions?

The U.S. Supreme Court ruled, in Massachusetts v. EPA, that greenhouse gases (GHGs) meets the definition of “air pollutant” in the CAA, and premised its decision in AEP v. Connecticut that the CAA displaced any federal common law right to compel reductions in CO₂ emissions from fossil fuel-fired power plants on its view that CAA section 111 applies to GHG emissions.

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5 For purposes of this summary, we present climate benefits from CO₂ that were estimated using the model average social cost of carbon (SCC) at a 3 percent discount rate. We emphasize the importance and value of considering the full range of SCC values, however, which include the model average at 2.5% and 5 percent, and the 95th percentile at 3 percent. Similarly, we summarize the health co-benefits in this summary at a 3 percent discount rate. We provide estimates based on additional discount rates in the RIA.

6 Greenhouse gas pollution is the aggregate group of the following gases: CO₂, methane (CH₄), nitrous oxide (N₂O), sulfur hexafluoride (SF₆), hydrofluorocarbons (HFCs), and perfluorocarbons (PFCs).


Congress established requirements under section 111 of the 1970 CAA to control air pollution from new stationary sources through NSPS. Specifically, as explained in greater detail in section II below, section 111(b) authorizes the EPA to set “standards of performance” for newly constructed new and (including modified) stationary sources from listed source categories to minimize limit emissions of air pollutants to the environment, and the EPA’s implementing regulations provide that define newly constructed new sources to include reconstructed sources. Under section 111(a)(1), the EPA must set these standards at the level of emission reduction that reflects the “best system of emission reduction ... adequately demonstrated”, taking into account technical feasibility, costs, and other factors.

For more than four decades, the EPA has used its authority under CAA section 111 to set cost-effective emission standards that ensure newly constructed, reconstructed and modified stationary sources use the best performing technologies to limit emissions of harmful air pollutants. In this proposal, the EPA is following the same well-established interpretation and application of the law under CAA section 111 to address GHG emissions from modified and reconstructed fossil fuel-fired

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9 40 CFR part 60 subpart A
electric steam generating units and natural gas-fired stationary combustion turbines.

2. What sources would be regulated by the proposed standards?

The proposed standards of performance would regulate GHG emissions from modified and reconstructed (1)fossil fuel-fired electric steam generating units – utility boilers and IGCC units (2) natural gas-fired stationary combustion turbines, whose non-GHG emissions are regulated under 40 CFR part 60, subpart Da, and (2) natural gas-fired stationary combustion turbines, whose non-GHG emissions are regulated under 40 CFR part 60, subpart KKKK. Today’s proposal only applies to units Natural gas-fired stationary combustion turbines that supply more than one-third of their potential electric output to the grid; therefore, peaking units are not covered subject to standards in by today’s proposal.

The CAA and the EPA’s implementing regulations define a “modification,” for purposes of NSPS applicability, as a physical or operational change that increases the source’s maximum achievable hourly rate of emissions, with certain exceptions.10

Under the EPA’s 1975 framework regulations covering CAA section 111 standards of performance, “reconstruction” means the replacement of components of an existing facility to an extent

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10 CAA Section 111(a)(4); 40 CFR 60.2, 60.14.
that (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 facility, and (2) it is technologically and economically feasible to meet the applicable standards.\textsuperscript{11}

3. Why is the EPA issuing this proposed rule?

GHG pollution threatens the American public's health and welfare by contributing to long-lasting changes in our climate system that can have a range of negative effects on human health and the environment. The impacts could include: longer, more intense and more frequent heat waves; more intense precipitation events and storm surges; less precipitation and more prolonged droughts in the West and Southwest; increased frequency and severity of short-term droughts in some other U.S. regions; more fires and insect pest outbreaks in American forests, especially in the West; and increased ground level ozone pollution, otherwise known as smog, which has been linked to asthma and premature death. Health risks from climate change are especially serious for children, the elderly and those with heart and respiratory problems.

Unlike most other air pollutants, GHGs may persist in the atmosphere from decades to millennia, depending on the specific

\textsuperscript{11} 40 CFR 60.15(b).
GHG. This special characteristic makes it crucial to act now to limit GHG emissions from fossil fuel-fired power plants, specifically emissions of CO₂, since they are the nation’s largest sources of carbon pollution.

As previously noted, on June 25, 2013, President Obama issued a Presidential Memorandum directing the EPA to address carbon pollution from the power sector. As an initial step to limit carbon pollution from power plants, on January 8, 2014, the EPA published a proposed rule to limit GHG emissions from new fossil fuel-fired electric steam generating units (utility boilers and IGCC units) and new natural gas-fired stationary combustion turbines. The EPA is now taking another step to limit carbon pollution in this country by issuing a proposed rule to limit GHG emissions from modified and reconstructed fossil fuel-fired electric steam generating units and modified and reconstructed natural gas-fired stationary combustion turbines.

Although we expect that the modification and reconstruction standards of performance in this rulemaking will apply to few, if any, sources, - since there have been a limited number in the past - these standards serve another important purpose that may affect a larger number of sources: providing an incentive, and the information needed, for existing sources to structure their actions to achieve their operating and business goals without triggering the modification or reconstruction standards. For
example, the modification standard encourages existing sources that undertake physical or operational changes to do so in a manner that does not increase their emission rate.

4. What is the EPA’s approach to setting standards for modified and reconstructed EGUs under CAA section 111(b)?

CAA section 111(b) requires the EPA to establish standards of performance that reflect the degree of emission limitation that is achievable through the application of the “best system of emission reduction” which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the EPA determines has been adequately demonstrated. The text and legislative history of CAA section 111, as well as relevant court decisions identify the 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 that the system would generate, and whether the standard would effectively promote further deployment or development of advanced technologies. The case law addressing section 111 makes it clear that the EPA has discretion in weighing these factors, and that as a result, the EPA may weigh them differently for different types of sources or air pollutants. See further discussion of this case law in section VI below.
For each of the standards being proposed in today’s action, the EPA considered a number of alternatives and evaluated them against the factors.

The BSER that we are proposing for each category of affected sources and the proposed standards of performance based on these BSER – as described immediately below – are based on that evaluation, as discussed in sections VI-IX below.

5. What are the BSER and the standard of performance for modified fossil fuel-fired utility boilers and IGCC units?

The EPA proposes that the BSER for modified fossil fuel-fired boilers and IGCC units is each unit’s own best potential performance based on a combination of best operating practices and equipment upgrades. Specifically, the EPA is proposing unit-specific emission standards consistent with this BSER determination and is co-proposing two alternative standards for modified utility steam generating units. In the first co-proposed alternative, modified utility boilers and IGCC units would be subject to a single emission standard. Specifically, under the first co-proposed alternative, a modified source would be required to meet a unit-specific emission limit determined by the affected source’s best demonstrated historical performance (in the years from 2002 to the time of the modification) with an additional two percent emission reduction. The EPA has determined that this standard can be met through a combination
of best operating practices and equipment upgrades. To account for facilities that have already implemented best practices and equipment upgrades, the proposal also specifies that modified facilities would not have to meet an emission standard more stringent than the corresponding standard for reconstructed EGUs. The EPA also solicits comment on whether, for units that have become subject to a CAA 111(d) plan, the period of best historical performance should be the years from 2002 to the time when the unit becomes subject to the CAA 111(d) plan, rather than to the time of the modification. This could address the concern that sources that make improvements to their CO₂ emission rate as a result of a 111(d) plan would have lower baseline emissions from which to calculate their required rate.

It is our interpretation, as we discuss in detail in the Legal Memorandum¹², that an existing source would continue to be subject to 111(d) requirements after it becomes a modified source, remains an existing source for the purposes of 111(d), whether the modification occurs before or after the promulgation of a 111(d) plan. Therefore EPA is co-proposing that modified sources would be required to meet unit-specific emission standards that would depend on the timing of the modification.


Comment [A15]: Is this a mistake? On p. 15, EPA makes this distinction: “all existing sources that become modified or reconstructed sources and which are subject to a CAA section 111(d) plan at the time of the modification or reconstruction”. At the very least, this is confusing.

EPA Response: Edit has been made
Sources that modify prior to becoming subject to a CAA section 111(d) plan would be required to meet the same standard described in the first co-proposal – that is, the modified source would be required to meet a unit-specific emission limit determined by the affected source’s best demonstrated historical performance (in the years from 2002 to the time of the modification) with an additional two percent emission reduction (based on equipment upgrades). Sources that modify after becoming subject to a CAA section 111(d) plan would be required to meet a unit-specific emission limit that would be determined by the 111(d) implementing authority and would be based on the source’s expected performance after implementation of identified unit-specific energy efficiency improvement opportunities. The BSER and standards of performance for modified fossil-fired electric utility steam generating units are discussed further in section VII.

6. What is the BSER and standard of performance for modified natural gas-fired stationary combustion turbines?

For modified natural gas-fired stationary combustion turbines, the EPA is proposing standards of performance based on efficient NGCC technology as the BSER. The emission limits proposed for these sources are 1,000 lb CO₂/MWh-gross for facilities with heat input ratings greater than 850 MMBtu/h, and 1,100 lb CO₂/MWh-gross for facilities with heat input ratings of
850 MMBtu/h or less. For sources that are subject to a CAA section 111(d) plan, the EPA is also soliciting comment on whether the sources should be allowed to elect, as an alternative to the otherwise applicable numeric standard, to instead meet a unit-specific emission standard that is determined by the 111(d) implementing authority based on implementation of identified energy efficiency improvement opportunities applicable to the source. This is discussed further in section IX.

7. What are BSER and the standard of performance for reconstructed fossil fuel-fired utility boilers and IGCC units?

For reconstructed utility boilers and IGCC units, the EPA is proposing a standard of performance with BSER based on the most efficient generating technology for these types of units (i.e., reconstructing the boiler to use higher steam, temperature and pressure, even if the boiler was not originally designed to do so\textsuperscript{13}). The proposed emission limit for these sources is 1,900 lb CO$_2$/MWh-net for sources with a heat input rating of greater than 2,000 MMBtu/h or 2,100 lb CO$_2$/MWh-net for sources with a heat input rating of 2,000 MMBtu/h or less. The difference in the proposed standards for larger and smaller

\textsuperscript{13} Steam with higher temperature and pressure has more thermal energy which can be more efficiently converted to electrical energy.
units is based on greater availability of higher pressure/temperature steam turbines (e.g. supercritical steam turbines) for larger units. The standards could also be met through other technology options such as natural gas co-firing or capture of a small quantity of CO₂ via partial CCS. This is discussed further in section VI below.

As discussed in the Legal Memorandum¹⁴, a reconstruction would have no effect on the applicability of an approved CAA section 111(d) plan; thus, a source that is subject to requirements in a CAA section 111(d) plan would remain subject to those requirements.

8. What are BSER and the standard of performance for reconstructed natural gas-fired stationary combustion turbines?

The EPA is proposing to find efficient NGCC technology to be the BSER for reconstructed stationary combustion turbines. Therefore, the EPA is proposing that larger units be required to meet a standard of 1,000 lb CO₂/MWh-gross and that smaller units be required to meet a standard of 1,100 lb CO₂/MWh-gross. This is discussed further in section VIII below.

A reconstruction would have no effect on the applicability of an approved CAA section 111(d) plan on the existing source; thus, a source that is subject to requirements in a CAA section

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¹⁴ Add cite to legal memo
111(d) plan would remain subject to those requirements, even after reconstruction.

9. How is EPA proposing to codify the requirements?

In the January 8, 2014 proposal of carbon pollution standards for new power plants (79 FR 1430), the EPA co-proposed two options for codifying applicable requirements for covered sources. Under the first option the EPA proposed to codify the standards of performance for the respective sources within existing 40 CFR part 60 subparts so that applicable GHG standards for electric utility steam generating units would be included in subpart Da and applicable GHG standards for stationary combustion turbines would be included in subpart KKKK. Under the second option, the EPA co-proposed to create a new subpart TTTT and to include all GHG standards of performance for covered sources in that newly created subpart.

In this action for modified and reconstructed sources, the EPA co-proposes the same two options for codifying the applicable standards. For consistency, the EPA intends - when it takes final action on this proposal and on the January 2014 proposal for new sources, respectively - to codify the standards in the same way for the sources addressed under the two proposals.

10. What is the organization and approach for this proposal?
Section II of this preamble provides a brief summary of background information on climate change impacts of GHG emissions, GHG emissions from fossil-fuel fired EGUs, the utility power sector, the statutory and regulatory background relevant to this rulemaking, and the EPA’s stakeholder outreach activities. Section II also contains additional information on the regulatory and litigation history of CAA section 111.

The specific proposed requirements for modified and reconstructed sources are described in detail in section III. The rationale for reliance on a rational basis to regulate GHG emissions from fossil fuel-fired EGUs and the rationale for the applicability requirements in today's proposal are presented in sections IV and V, respectively. Sections VI through IX describe the rationale for each of the proposed emission standards, including an explanation of the determination of the BSER for reconstructed fossil fuel-fired utility boilers and IGCC units and modified fossil fuel-fired utility boilers and IGCC units, as well as for reconstructed natural gas-fired stationary combustion turbines and modified natural gas-fired stationary combustion turbines. Impacts of the proposed action are described in section X. A discussion of statutory and executive order reviews is provided in section XI, and the statutory authority for this action is provided in section XII.
It should be noted that this rulemaking overlaps in certain respects with two other related rulemakings: the January 2014 proposed rulemaking for CO₂ emissions from new affected EGUs, and the rulemaking for existing EGUs that the EPA is proposing at the same time as the present rulemaking. In a number of places in this preamble, the EPA cross-references parts of those two rulemakings. However, each of these three rulemakings is independent of the other two, and each has its own rulemaking docket. Accordingly, anyone who wishes to comment on any aspect of this rulemaking, including anything described by a cross-reference to one of the other two related rulemakings, should make those comments on this rulemaking.

C. Does this action apply to me?

The entities potentially affected by the proposed standards are shown in Table 2 below.

**Table 2. Potentially Affected Entities**

<table>
<thead>
<tr>
<th>Category</th>
<th>NAICS Code</th>
<th>Examples of Potentially Affected Entities</th>
</tr>
</thead>
<tbody>
<tr>
<td>Industry</td>
<td>221112</td>
<td>Fossil fuel electric power generating units.</td>
</tr>
<tr>
<td>Federal Government</td>
<td>221112ᵇ</td>
<td>Fossil fuel electric power generating units owned by the federal government.</td>
</tr>
<tr>
<td>State/Local Government</td>
<td>221112ᵇ</td>
<td>Fossil fuel electric power generating units owned by municipalities.</td>
</tr>
<tr>
<td>Tribal Government</td>
<td>921150</td>
<td>Fossil fuel electric power generating units in Indian Country.</td>
</tr>
</tbody>
</table>
a Includes North American Industry Classification (NAICS) categories for source categories that own and operate electric power generating units (including boilers and stationary combined cycle combustion turbines).
b Federal, state or local government-owned and operated establishments are classified according to the activity in which they are engaged.

This table is not intended to be exhaustive, but rather to provide a guide for readers regarding entities likely to be affected by this proposed action. 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 any 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).

II. Background

In this section, we discuss climate change impacts from GHG emissions, both on public health and public welfare, present information about GHG emissions from fossil-fuel fired EGUs, describe the utility power sector and summarize the statutory and regulatory background relevant to this rulemaking. We close

15 This background section is intended to provide the same or very similar background information as provided in the companion proposals for new sources (79 FR 1430) and existing sources (the 111(d) proposal in today’s Federal Register). Any minor differences in phrasing between this proposal and the companion proposals are not intended to state a substantive difference.
this section by describing stakeholder outreach and a brief history of modifications and reconstructions in the power sector.

A. Climate Change Impacts from GHG Emissions

In 2009, the EPA Administrator issued the document we refer to as the GHG Endangerment Finding under CAA section 202(a)(1). In the Endangerment Finding, which focused on public health and public welfare impacts within the U.S., the Administrator found that elevated concentrations of GHGs in the atmosphere may reasonably be anticipated to endanger the public health and welfare of current and future generations. We summarize these adverse effects of GHGs on public health and welfare briefly here.17

16 “Endangerment and Cause or Contribute Findings for Greenhouse Gases under Section 202(a) of the Clean Air Act,” 74 FR 66,496 (Dec. 15, 2009) (“Endangerment Finding”).
17 The January 8, 2014, preamble to the proposed GHG standards for new EGUs (79 FR 1430) and the RIA supporting that proposal include a more detailed summary of the public health and welfare impacts detailed in the 2009 Endangerment Finding, as well as a discussion of the science supporting the EPA’s conclusions regarding the question of whether GHG endanger public health and welfare including: 1) the process by which the Administrator reached the Endangerment Finding in 2009; 2) the EPA’s response in 2010 to ten administrative petitions for reconsideration of the Endangerment Finding (the Reconsideration Denial); and 3) the decision by the United States Court of Appeals for the District of Columbia Circuit in 2012 to uphold the Endangerment Finding and the Reconsideration Denial.
1. Public Health Impacts Detailed in the 2009 Endangerment Finding

Anthropogenic emissions of GHGs and consequent climate change caused by human emissions of GHGs threaten public health in multiple ways. By raising average temperatures, climate change increases the likelihood of heat waves, which are associated with increased deaths and illnesses. While climate change also leads to increases in the likelihood of reductions in cold-related mortality, evidence indicates that the increases in heat mortality will be larger than the decreases in cold mortality in the U.S. Compared to a future without climate change, climate change is expected to increase ozone pollution over broad areas of the country, including large population areas with already unhealthy surface ozone levels in the largest metropolitan areas with the worst ozone problems, and thereby increase the risk of morbidity and mortality. Other public health threats also stem from projected increases in intensity or frequency of extreme weather associated with climate change, such as increased hurricane intensity, increased frequency of intense storms and heavy precipitation. Increased coastal storms and storm surges due to rising sea levels are expected to cause

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18 “Endangerment and Cause or Contribute Findings for Greenhouse Gases under Section 202(a) of the Clean Air Act,” 74 FR 66,496 (Dec. 15, 2009) (“Endangerment Finding”).
increased drownings and other health impacts. Children, the elderly, and the poor are among the most vulnerable to these climate-related health effects.

2. Public Welfare Impacts Detailed in the 2009 Endangerment Finding

Anthropogenic emissions of GHGs and consequent climate change caused by human emissions of GHGs also threatens public welfare in multiple ways. Climate changes are expected to place large areas of the country at serious risk of reduced water supplies, increased water pollution, and increased occurrence of extreme events such as floods and droughts. Coastal areas are expected to face increased risks from storm and flooding damage to property, as well as adverse impacts from rising sea level, such as land loss due to inundation, erosion, wetland submergence, and habitat loss. Climate change is expected to result in an increase in peak electricity demand, and extreme weather from climate change threatens energy, transportation and water resource infrastructure. Climate change may exacerbate ongoing environmental pressures in certain settlements, particularly in Alaskan indigenous communities. Climate change also is very likely to fundamentally rearrange

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U.S. ecosystems over the 21st century. Though some benefits may balance adverse effects on agriculture and forestry in the next few decades, the body of evidence points towards increasing risks of net adverse impacts on U.S. food production, agriculture and forest productivity as temperature continues to rise. These impacts are global and may exacerbate problems outside the U.S. that raise humanitarian, trade, and national security issues for the U.S.

3. New Scientific Assessments

As outlined in Section VIII.A. of the 2009 Endangerment Finding, the EPA’s approach to providing the technical and scientific information to inform the Administrator’s judgment regarding the question of whether GHGs endanger public health and welfare was to rely primarily upon the recent, major assessments by the U.S. Global Change Research Program (USGCRP), the Intergovernmental Panel on Climate Change (IPCC), and the National Research Council (NRC) of the National Academies. These assessments addressed the scientific issues that the EPA was required to examine, were comprehensive in their coverage of the GHG and climate change issues, and underwent rigorous and exacting peer review by the expert community, as well as rigorous levels of U.S. government review. Since the administrative record concerning the Endangerment Finding closed following the EPA’s 2010 Reconsideration Denial, a number of
additional such assessments have been released. These assessments include the IPCC’s 2012 “Special Report on Managing the Risks of Extreme Events and Disasters to Advance Climate Change Adaptation” (SREX) and the Working Group I contribution to the 2013-2014 Fifth Assessment Report (AR5), the USGCRP’s 2014 “Climate Change Impacts in the United States” (Climate Change Impacts), and the NRC’s 2010 “Ocean Acidification: A National Strategy to Meet the Challenges of a Changing Ocean” (Ocean Acidification), 2011 “Report on Climate Stabilization Targets: Emissions, Concentrations, and Impacts over Decades to Millennia” (Climate Stabilization Targets), 2011 “National Security Implications for U.S. Naval Forces” (National Security Implications), 2011 “Understanding Earth’s Deep Past: Lessons for Our Climate Future” (Understanding Earth’s Deep Past), 2012 “Sea Level Rise for the Coasts of California, Oregon, and Washington: Past, Present, and Future”, 2012 “Climate and Social Stress: Implications for Security Analysis” (Climate and Social Stress), and 2013 “Abrupt Impacts of Climate Change” (Abrupt Impacts) assessments.

The EPA has reviewed these new assessments and finds that the improved understanding of the climate system they present strengthens the case that GHGs are endangering public health and welfare.
In addition, these assessments highlight the urgency of the situation as the concentration of CO₂ in the atmosphere continues to rise. Absent a reduction in emissions, a recent NRC of the National Academies assessment by the NRC projected that concentrations by the end of the century would increase to levels that the Earth has not experienced for millions of years. In fact, that assessment stated that “the magnitude and rate of the present greenhouse gas increase place the climate system in what could be one of the most severe increases in radiative forcing of the global climate system in Earth history.”

What this means, as stated in another NRC assessment, is that:

Emissions of carbon dioxide from the burning of fossil fuels have ushered in a new epoch where human activities will largely determine the evolution of Earth’s climate. Because carbon dioxide in the atmosphere is long lived, it can effectively lock Earth and future generations into a range of impacts, some of which could become very severe. Therefore, emission reductions choices made today matter in determining impacts experienced not just over the next few decades, but in the coming centuries and millennia.

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22 National Research Council, Climate Stabilization Targets, p. 3.
Moreover, due to the time-lags inherent in the Earth's climate, the National Climate Stabilization Targets assessment notes that the full warming from any given concentration of CO₂ reached will not be realized for several centuries.

The recently released USGCRP “Climate Change Impacts” assessment emphasizes that climate change is already happening now and it is happening in the U.S. The assessment documents the increases in some extreme weather and climate events in recent decades, the damage and disruption to infrastructure and agriculture, and projects continued increase and more severe changes across a wide range of peoples, sectors, and ecosystems.

These assessments underscore the urgency of reducing emissions now. These today’s emissions will otherwise lead to raised atmospheric concentrations for thousands of years, and raised Earth system temperatures for even longer. Emission reductions today will benefit the public health and public welfare of current and future generations.

Finally, it should be noted that the concentration of CO₂ in the atmosphere continues to rise dramatically. At the time of the In 2009, the year of the Endangerment Finding, the average concentration of CO₂ as measured on top of Mauna Loa was 387

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parts per million (ppm). The average concentration in 2013 was 396 ppm. And the monthly concentration in March-April 2014 was 401 ppm, the first time a monthly average has exceeded (will update with most current data as of date of signature), the level had increased to 400 ppm since record keeping began, and for at least the past 800,000 years according to ice core records. B. GHG Emissions from Fossil Fuel-fired EGUs

Among stationary sources in the U.S., fossil fuel-fired EGUs are by far the largest emitters of GHGs, primarily in the form of CO₂, among stationary sources in the U.S., and among fossil fuel-fired EGUs, coal-fired units are by far the largest emitters. This section describes the amounts of those emissions and places those amounts in the context of the national inventory of GHGs.

The EPA prepares the official U.S. Inventory of Greenhouse Gas Emissions and Sinks (the U.S. GHG Inventory) to comply with commitments under the United Nations Framework Convention on Climate Change (UNFCCC). This inventory, which includes recent

Comment [A18]: EPA could consider adding pre-industrial concentration for reference.
EPA: A link to historical concentrations has been provided for readers.

25 http://www.esrl.noaa.gov/gmd/ccgg/trends/.
trends, is organized by industrial sectors. It provides the information in Table 3 below, which presents total U.S. anthropogenic emissions and sinks of GHGs, including CO₂ emissions, for the years 1990, 2005 and 2012.

Table 3. U.S. GHG Emissions and Sinks by Sector (teragram carbon dioxide equivalent (Tg CO₂ Eq.))

<table>
<thead>
<tr>
<th>SECTOR</th>
<th>1990</th>
<th>2005</th>
<th>2012</th>
</tr>
</thead>
<tbody>
<tr>
<td>Energy</td>
<td>5,256.55</td>
<td>5,260.16</td>
<td>5,489.65</td>
</tr>
<tr>
<td>Industrial Processes</td>
<td>316.1</td>
<td>330.2</td>
<td>334.9</td>
</tr>
<tr>
<td>Solvent and Other Product Use</td>
<td>4.4</td>
<td>4.4</td>
<td>4.4</td>
</tr>
<tr>
<td>Agriculture</td>
<td>473.9</td>
<td>512.2</td>
<td>526.3</td>
</tr>
<tr>
<td>Land Use, Land-Use Change and Forestry</td>
<td>13.7</td>
<td>25.5</td>
<td>37.8</td>
</tr>
<tr>
<td>Waste</td>
<td>165.0</td>
<td>133.2</td>
<td>124.0</td>
</tr>
<tr>
<td>Total Emissions</td>
<td>6,229.66</td>
<td>6,233.2</td>
<td>6,501.56</td>
</tr>
<tr>
<td>Land Use, Land-Use Change and Forestry (Sinks)</td>
<td>(831.3)</td>
<td>(1,030.7)</td>
<td>(979.43)</td>
</tr>
</tbody>
</table>

27 Sinks are a physical unit or process that stores GHGs, such as forests or underground or deep sea reservoirs of carbon dioxide.


http://epa.gov/climatechange/ghgemissions/usinventoryreport.html
Net Emissions (Sources and Sinks) 5,398.5 5,402.1 6,214.2 6,223.1 5,522.1 5,546.3

Total fossil energy-related CO₂ emissions (including both stationary and mobile sources) are the largest contributor to total U.S. GHG emissions, representing 77.97 percent of total 2012 GHG emissions. In 2012, fossil fuel combustion by the electric power sector – entities that burn fossil fuel and whose primary business is the generation of electricity – accounted for 38.7 percent of all energy-related CO₂ emissions. Table 4 below presents total CO₂ emissions from fossil fuel-fired EGUs, for years 1990, 2005 and 2012.

Table 4. U.S. GHG CO₂ Emissions from Generation of Electricity from Combustion of Fossil Fuels (Tg CO₂-Eq.)

<table>
<thead>
<tr>
<th>GHG EMISSIONS</th>
<th>1990</th>
<th>2005</th>
<th>2012</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total CO₂ emissions from fossil fuel combustion EGUs</td>
<td>1,820.8</td>
<td>2,402.1</td>
<td>2,023.6</td>
</tr>
<tr>
<td>from coal</td>
<td>1,547.6</td>
<td>1,983.8</td>
<td>1,512.2</td>
</tr>
<tr>
<td>from natural gas</td>
<td>175.3</td>
<td>318.8</td>
<td>492.2</td>
</tr>
<tr>
<td>from petroleum</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

C. The Utility Power Sector

Electricity in the U.S. is generated by a range of sources - from power plants that use fossil fuels such as coal, oil and natural gas, to non-fossil sources, such as nuclear, solar, wind and hydroelectric power. Currently, the majority of power in the U.S. is generated from the combustion of coal, natural gas and other fossil fuels.

Natural gas-fired EGUs typically use one of two technologies: NGCC or simple cycle combustion turbines. NGCC units first generate power from a combustion turbine (the combustion cycle). The unused heat from the combustion turbine is then routed to a heat recovery steam generator (HRSG) that generates steam which is 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 use a single combustion turbine to produce electricity (i.e., there is no heat recovery). The power output from these simple cycle combustion turbines can be easily ramped up and down making them ideal for “peaking” operations.

Coal-fired utility boilers are primarily either PC boilers or fluidized bed (FB) boilers. At a PC boiler, the coal is crushed (pulverized) into a powder in order to increase its
surface area. The coal powder is then blown into a boiler and burned. In a coal-fired boiler using FB combustion, the coal is burned in a layer of heated particles suspended in flowing air.

Power can also be generated using gasification technology. An IGCC unit gasifies coal or petroleum coke to form a syngas composed of carbon monoxide and hydrogen, which can be combusted in a combined cycle system to generate power.

D. Statutory Background

CAA section 111 authorizes the EPA to prescribe new source performance standards (NSPS) applicable to certain new stationary sources (including modified and reconstructed sources).\(^32\) As a preliminary step to regulation, the EPA must list 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 section 111.\(^33\)

Once the EPA has listed a source category, the EPA proposes and then promulgates “standards of performance” for “new sources” in the category.\(^34\) A “new source” is “any stationary

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\(^32\) CAA section 111(b)(1)(A).
\(^33\) See generally 40 CFR subparts D-MMMM.
\(^34\) CAA section 111(b)(1)(B).
source, the construction or modification of which is commenced after," in general, the date of the proposal.35 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.”36 The EPA, through regulations, has determined that certain types of changes are exempt from consideration as a modification.37

The EPA’s 1975 framework regulations also provide that an existing source is considered a new source if it undertakes a “reconstruction,” which is the replacement of components of an existing facility to an extent that (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 facility, and (2) it is technologically and economically feasible to meet the applicable standards.38

CAA section 111(a)(1) defines a “standard of performance” 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

35 CAA section 111(a)(2).
36 CAA section 111(a)(4).
37 40 CFR 60.2, 60.14(e).
38 40 CFR 60.15.
(taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated. This definition makes clear that the standard of performance must be based on “the best system of emission reduction ... adequately demonstrated” (BSER). The standard that the EPA develops, based on the BSER, is commonly a numeric emission limit, expressed as a performance level (e.g., a rate-based standard). Generally, the EPA does not prescribe a particular technological system that must be used to comply with a standard of performance. Rather, sources generally may select any measure or combination of measures that will achieve the emissions level of the standard. In establishing standards of performance, the EPA has significant discretion to create subcategories based on source type, class or size.

When the EPA establishes NSPS for new sources in a particular source category, the EPA is also required, under CAA section 111(d)(1), to establish requirements for existing sources in that source category for any air pollutant that, in general, is not regulated under the CAA section 109 requirements for the National Ambient Air Quality Standards or regulated under the CAA section 112 requirements for hazardous air

39 CAA section 111(b)(5)
40 CAA section 111(b)(2)
pollutants. Unlike CAA section 111(b), which gives EPA direct authority to set national standards, CAA section 111(d) requires the EPA to promulgate emission guidelines directing states to develop and submit, for EPA approval, state plans that include standards of performance for the existing sources.

E. Regulatory Background

In 1971, the EPA initially included fossil fuel-fired (which includes natural gas, petroleum and coal) EGUs that use steam-generating boilers in a category that it listed under CAA section 111(b)(1)(A), and the EPA promulgated the first set of standards of performance for sources in that category, which it codified in subpart D. In 1977, the EPA initially included fossil fuel-fired combustion turbines in a category that the EPA listed under CAA section 111(b)(1)(A), and the EPA promulgated standards of performance for that source category in 1979, which the EPA codified in subpart GG.

The EPA has revised those regulations, and in some instances, has revised the codifications (that is, the 40 CFR

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41 36 FR 5931 (March 31, 1971)
part 60 subparts), several times over the ensuing decades. In 1979, the EPA divided subpart D into 3 subparts – Da (“Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978”), Db (“Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units”) and Dc (“Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units”) – in order to codify separate requirements that it established for these subcategories.45 In 2006, the EPA created subpart KKKK, “Standards of Performance for Stationary Combustion Turbines,” which applied to certain sources previously regulated in subparts Da and GG.46 None of these subsequent rulemakings, including the revised codifications, however, constituted a new listing under CAA section 111(b)(1)(A).

The EPA promulgated amendments to subpart Da in 2006, which included new standards of performance for criteria pollutants for EGUs, but no standards of performance for GHG emissions.47 Petitioners sought judicial review of the rule by the D.C.

45 44 FR 33,580 (June 11, 1979)
46 71 FR 38497 (July 6, 2006), as amended at 74 FR 11861 (March 20, 2009).
Circuit, contending, among other issues, that the rule was required to include standards of performance for GHG emissions from EGUs.\textsuperscript{48} The January 8, 2014 preamble to the proposed CO\textsubscript{2} standards for new EGUs\textsuperscript{49} includes a discussion of the GHG-related litigation of the 2006 Final Rule as well as other GHG-associated litigation.

F. Stakeholder Outreach

The EPA has engaged extensively with a broad range of stakeholders and the general public regarding climate change, carbon pollution from power plants, and carbon pollution reduction opportunities. These stakeholders included industry and electric utility representatives, state and local officials, tribal officials, labor unions and non-governmental organizations.

In February and March 2011, early in the process of developing carbon pollution standards for new power plants, the EPA held five listening sessions to obtain information and input from key stakeholders and the public. Each of the five sessions had a particular target audience: the electric power industry, environmental and environmental justice organizations, states and tribes, coalition groups, and the petroleum refinery industry.

\textsuperscript{48}State of New York, et al. v. EPA, No. 06-1322.
\textsuperscript{49}79 FR 1430
The EPA has conducted subsequent outreach sessions: the vast majority of which occurred between September 2013 and November 2013. The agency held 11 public listening sessions; one national listening session in Washington, DC and 10 listening sessions in locations across the country. In addition to the 11 public listening sessions, the EPA has held hundreds of meetings with individual stakeholder groups, and meetings that brought together a variety of stakeholders to discuss a wide range of issues related to the electricity sector and regulation of GHGs under the CAA. The agency provided and encouraged multiple opportunities to engage with each one of the 50 states. The agency met with electric utility associations and electricity grid operators. Agency officials have engaged with labor unions and with leaders representing large and small industries. Because of the focus of the standard on the electricity sector, many of the EPA’s meetings with industry have been with utilities and industry representatives directly related to the electricity sector. The agency has also met with energy industries such as coal and natural gas interests. In addition, the agency has met with companies that offer new technology to prevent or reduce carbon pollution, including companies that represent renewable energy and energy efficiency interests. The EPA has also met with representatives of energy intensive industries, such as the iron and steel and aluminum industries,
to help understand the issues related to large industrial purchasers of electricity. Agency officials engaged with representatives of environmental justice organizations, environmental groups, and religious organizations.

Although this stakeholder outreach was primarily framed around the GHG emission guidelines for existing EGUs, the outreach encompassed issues relevant to this proposed rulemaking for modified and reconstructed EGUs. For example, existing EGUs would be subject to standards for modified and reconstructed EGUs should they undertake modification or reconstruction actions, and, thus it is important that we understand previous state and stakeholder experience with reducing CO₂ emissions in the power sector.

A detailed discussion of this stakeholder outreach is included in the preamble to the GHG emission guidelines for existing affected EGUs being proposed in a separate action today.

G. Modifications and Reconstructions

1. Modifications

The EPA’s current regulations\(^50\) define an NSPS “modification” as a physical or operational change that

\(^50\) The discussion of the EPA’s regulations in this rulemaking is for background purposes only. The EPA is not re-opening, and thus is not soliciting comment on, any provision in its existing regulations.
increases the source’s maximum achievable hourly rate of emissions, with certain exemptions.\(^{51}\)

Based on current information, the EPA believes that projects may involve equipment changes to improve efficiency that could have the effect of increasing a source’s maximum achievable hourly emission rate (lb CO\(_2\)/h), even while decreasing its actual output based emission rate (lb CO\(_2\)/MWh). However, based on current information, the most likely projects that could increase the maximum achievable hourly rate of CO\(_2\) emissions would involve the installation of add-on control equipment required to meet CAA requirements for criteria and hazardous air pollutants. These increases in CO\(_2\) emissions would generally be small and would occur as a chemical by-product of the operation of the control equipment. All of these actions, however, would be exempted from the definition of modification.\(^{52}\)

There are, however, some actions that could potentially trigger the modification provisions of 111(b). For example, in some cases, generation from a fossil fuel-fired electric utility steam generating unit is limited not by the size of the boiler, but by other factors, such as the size of the steam turbine or limitations in the particulate control equipment that, in turn, limit the amount of coal that can be combusted. If the steam

\(^{51}\) 40 CFR 60.2, 60.14.

\(^{52}\) 40 CFR 60.14.
turbine or particulate control device is upgraded, more coal can be combusted in the boiler, increasing hourly emissions.

Our base of knowledge concerning the types of NSPS modifications has depended largely on self-reporting by power plants and on the enforcement actions brought against power plants. Over the lengthy history of the NSPS program, the number of modifications that we are aware of is limited.

2. Comments on the April 2012 Proposal for New Sources Related to Modifications

In the April 13, 2012 proposed Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units (77 FR 22392)\textsuperscript{53}, the EPA did not propose standards of performance for modified sources; however, it did specifically request comment on the types of modifications that may be expected and on the appropriate control measures that may be applied. The agency received a number of comments addressing standards for modified and reconstructed EGUs.\textsuperscript{54} The EPA subsequently withdrew that proposed rulemaking.\textsuperscript{55} While many of those comments informed today’s proposal, the EPA is not responding to those comments in this rulemaking, and if members

\textsuperscript{53} The proposal was subsequently withdrawn with the publication of the January 8, 2014 proposal.
\textsuperscript{54} The comments are available in the rulemaking docket. Docket ID: EPA-HQ-OAR-2011-0660.
\textsuperscript{55} 79 FR 1352
of the public wish to express views on this rulemaking they must do so in comments on this rulemaking.

Many of those comments emphasized that a standard of performance that is based on CCS (or partial CCS) is not appropriate for modified EGUs. Some commenters suggested that a well-designed CAA section 111(d) program could obviate the need to set separate standards of performance for modified sources. Several commenters disagreed with EPA’s assertion that it lacked adequate information to propose standards for modified sources (at that time), stating that proposed standards should be based on energy efficiency measures.

3. Reconstructions

The EPA’s framework regulations, interpreting the definition of “new source” in CAA section 111(a)(2), provide that an existing source, “upon reconstruction,” becomes subject to the standard of performance for new sources. The regulations define reconstruction as the replacement of components of an existing facility to such an extent that (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 facility, and (2) it is technologically and economically feasible to meet the applicable standards set forth.

56 40 CFR 60.15(a)
Thus, a reconstruction occurs if the existing source replaces components to such an extent that the capital costs of the new components exceed 50 percent of the capital costs of an entirely new facility, even if the existing source does not increase its emissions. In addition, the component replacement constitutes a reconstruction only if it is technologically and economically feasible for the source to meet the applicable standards. **The purpose of the reconstruction provision is to discourage the perpetuation of a facility, instead of replacing it at the end of its useful life with a newly constructed affected facility.**

The regulations require the owner or operator of an existing source that proposes to replace components to an extent that exceeds the 50 percent level to notify the EPA and provide specified information. **This information must include: the name and address of the owner or operator; the location of the existing facility; a brief description of the existing facility and the components which are to be replaced; a description of existing and proposed air pollution control equipment; an estimate of the fixed capital cost of the replacements and of constructing a comparable entirely new facility; the estimated life of the existing facility after the replacements; and, including** a discussion of any economic or technical limitations in this part.
the facility may have in complying with the applicable standards of performance after the proposed replacements.\footnote{The regulations require the EPA to determine, within a specified time period, whether the proposed replacement constitutes a reconstruction.} The determination shall be based on: the fixed capital cost in comparison to the cost to construct a comparable entirely new facility; the estimated life of the facility after the replacements compared to the life of a comparable entirely new facility; the extent to which the components being replaced cause or contribute to emissions from the facility; and any economic or technical limitations on compliance with applicable standards of performance which are inherent in the proposed replacements.

Historically, few EGUs have undertaken reconstructions. Because of the relative prices of coal and natural gas, and the relative costs of reconstructing an existing coal-fired EGU and newly constructing an \textit{entirely new} NGCC unit, the EPA expects that few, if any, existing coal-fired EGUs will undertake projects that will qualify the unit to be a reconstructed source during the analysis period of this rulemaking (i.e., through 2025). The EPA also does not expect existing NGCC units to undertake reconstructions during the analysis period (i.e.,

\footnote{40 CFR 60.15(d)-(e)}
Because most of them are relatively young (over 80 percent of the NGCC fleet came on-line after 2000),

While there are specific provisions in the EPA’s implementing regulations at 40 CFR 60.15 on what constitutes a reconstructed source (as just described), there is not such guidance on when an existing source replaces components to such a degree that it goes beyond a reconstruction and becomes essentially a newly constructed source. Historically there has been little need to distinguish between reconstructed sources and newly constructed sources as the standards of performance are typically the same for either. However, the standards proposed in today’s action are different – for reasons we explain later – and, therefore, there is a need to clearly delineate between a reconstructed source and a newly constructed source. For example, it is clear that an entirely new greenfield facility would constitute a newly constructed source. It is EPA’s view that, a new unit that is built on property contiguous with an existing source – but not in the same footprint as the existing source – would also constitute a newly constructed source. And, it is EPA’s view that a unit that entirely, or for all practical purposes, completely replaces an existing source by being constructed on the replaced source’s existing footprint would also constitute a newly constructed source. The EPA solicits comment on the delineation between a reconstructed
source, which would be subject to standards proposed in today’s action, and a newly constructed source, which would be subject to standards proposed in the January 2014 proposal (FR 79 1430), for those situations where significant equipment is being replaced (enough to exceed the reconstruction threshold) but the entire unit is not being rebuilt.

In addition, the EPA requests comment on having an upper capital cost threshold for reconstruction, such that facilities that exceed that threshold would be subject to the standard of performance for newly constructed sources. With respect to this concept, the EPA requests comment on both: (1) the idea of having an upper threshold and (2) the appropriate upper threshold. With respect to the appropriate upper threshold, EPA specifically requests comment on an upper threshold within the range of 75 to 100 percent of the cost of an entirely new and comparable facility. Finally, the EPA requests comment on whether this upper threshold should be coupled with a provision comparable to 40 CFR 60.15(b)(2) and 60.15(f)(4), such that a facility that exceeded the upper threshold would not be subject to the new construction standard if it was technologically and economically infeasible for that facility to meet the new construction standard.

4. Comments on the April 2012 Proposal for New Sources Related to Reconstructions
In the April 13, 2012 proposed Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units (77 FR 22392), the EPA did not propose standards of performance for reconstructed sources; however, it did specifically request comment on the types of reconstructions that may be expected and on the appropriate control measures that may be applied. The agency received a number of comments addressing standards for reconstructed EGUs.\textsuperscript{58} As noted above, the agency subsequently withdrew that proposal and is not responding to those comments in this rulemaking, so that if members of the public wish to express views on this rulemaking they must do so in comments on this rulemaking.

Many of the comments on the April 13, 2012 proposal supported a delay in proposing standards for reconstructed sources. Others did not favor the delay and suggested, instead, that reconstructed sources be subject to the same standard as newly constructed sources. One commenter expressed concern that an existing source that elected to retrofit with CCS technology (perhaps in reliance on enhanced oil recovery (EOR) markets) might trigger the requirements for a reconstruction due to the high cost of CCS technology. The commenter suggested that the EPA exclude the cost of retrofitting CCS technology in order to

\textsuperscript{58} The comments are available in the rulemaking docket. Docket ID: EPA-HQ-OAR-2011-0660.
eliminate barriers to voluntary use of that technology. Several commenters expressed concern that a reconstruction could be essentially a new plant built on a few remaining parts of an old plant. The commenters expressed concern that such reconstructed sources would face a standard that is much less stringent than a newly constructed greenfield source.

III. Proposed Requirements for Modified and Reconstructed Sources

A. Applicability Requirements

We generally refer to fossil fuel-fired electric generating units that would be subject to an emission standard in this rulemaking as “affected” or “covered” sources, units, facilities or simply as EGUs. These sources meet both the definition of “affected” and “covered” EGUs subject to an emission standard as provided by this proposed rule, and the criteria for being considered “modified” and “reconstructed” sources as defined under the provisions of CAA section 111 and the EPA’s regulations.

The EPA is proposing generally the same applicability requirements, for purposes of this rule, that the
EPA proposed in the January 2014 proposal.\textsuperscript{59,60} This section
describes those requirements.

\textbf{To be considered an EGU under\textsuperscript{61} Subpart Da currently defines an EGU as the boiler or IGCC must be that is:} (1) “capable of
combusting more than 250 MMBtu/h heat input of fossil fuel,”\textsuperscript{61} (2) “constructed for the purpose of supplying more than one-third of its potential net-electric output capacity — to any utility power distribution system for sale”\textsuperscript{62} (that is, to the grid), and (3) “constructed for the purpose of supplying — more than 25 MW net-electric output” to the grid.\textsuperscript{63} In the January 2014 proposal, we proposed to revise the third criterion to read “more than 219,000 MWh,” as opposed to “25 MW,” net-electrical

\textsuperscript{59} See 79 FR at 1,445/2 –and 1,446/3. Note that the statements in the January 2014 Proposal that “existing sources undertaking modifications or reconstructions; or certain projects under development, including the proposed Wolverine EGU project in Rogers City, Michigan (and, perhaps, up to two others)” are not subject to that rulemaking, 79 FR at 1,446/4, are not relevant for purposes of the present rulemaking concerning modifications and reconstructions.

\textsuperscript{60} In the January 2014 proposal, the EPA solicited comment on whether certain applicability requirements were appropriate in light of the fact that they assumed that the source had an operating history. In this rulemaking, the affected sources that would be undertaking modifications or reconstructions do have an operating history. As a result, to the extent the solicitation of comment in the January 2014 just described may be read to identify concerns about those applicability requirements, those concerns do not apply to this rulemaking.

\textsuperscript{61} E.g., 40 CFR 60.40Da(a)(1).

\textsuperscript{62} 40 CFR 60.41Da (definition of (“Electric utility steam-generating unit”).

\textsuperscript{63} Id.
output to the grid. This proposed change to 219,000 MWh net sales is consistent with the EPA Acid Rain Program (ARP) definition, and we have concluded that it is functionally equivalent to the 25 MW net sales language. The 25 MW sales value has been interpreted to be the continuous sale of 25 MW of electricity on an annual basis, which is equivalent to 219,000 MWh. In the January 2014 proposal we proposed to include two additional applicability criteria specific to applicability with the GHG standards: (1) that a facility actually sells more than 1/3 of their potential electric output and more than 219,000 MWh to the grid on an annual basis for boilers and IGCC facilities and on a 3 year average for combustion turbines (2) that the GHG standards are not applicable to facilities that combust 10 percent or less fossil fuel on a 3 year average. In this proposal we are not proposing that any of these additional applicability criteria apply for modified or reconstructed boilers or IGCC facilities. Therefore, any modified or reconstructed boiler or IGCC facility that meets the general applicability of subpart Da would also be subject to the GHG requirements. For stationary combustion turbines we are proposing to maintain all of these criteria, along with the additional criteria specific to stationary combustion turbines, included in the January 2014 proposal, that only stationary
combustion turbines that combust over 90 percent on a 3 year rolling average basis are subject to a numerical GHG standard.

Because a modified or reconstructed source will have an operating history, unlike a new source, we are proposing to define an EGU slightly differently for purposes of this rule. We are proposing to include criteria that must be met in addition to the “constructed for the purpose of supplying more than one-third of its potential electric output capacity” to the grid criterion.

First, because the source will have an operating history reflecting its additional sales to the grid, we are adding a new criterion that a unit actually “supplies more than one-third of its potential electric output” to the grid. Combined with the three-year rolling average methodology to determine if the one-third criteria is met (as explained further below), this approach makes it clear that a unit that was not originally constructed to supply more than one-third of its potential electric output to the grid but does so for one year does not automatically become affected. Both criteria would also be used in subparts KKKK and TTTT.

Second, we are proposing to revise the third criterion to read “constructed for the purpose of supplying “more than 219,000 MWh,” as opposed to “constructed for the purpose of supplying 25 MW,” net-electrical output to the grid. This
A proposed change to 219,000 MWh net sales is consistent with the EPA Acid Rain Program (ARP) definition and in the January 8, 2014 proposal, and we have concluded that it is functionally equivalent to the 25 MW net sales language. The 25 MW sales value has been interpreted to be the continuous sale of 25 MW of electricity on an annual basis, which is equivalent to 219,000 MWh. We are also proposing to revise the averaging period for electric sales from an annual basis to a three-year rolling average for stationary combustion turbines.

Finally, we are proposing to add a new applicability criterion that is not currently in subpart Da: EGUs, for which 10 percent or less of the heat input over a three-year period is derived from a fossil fuel, are not subject to any of the proposed CO₂ standards.

Consistent with the January 2014 proposal, we are proposing several additional adjustments to the way applicability is currently determined under subpart Da for purposes of modifications and reconstructions. First, we are proposing that the definition of “potential electric output” be revised to include “or the design net electric output efficiency” as an alternative to the default one-third efficiency value (i.e., the proposed definition is “33 percent or the design net electric output efficiency times” the maximum design heat input capacity of the steam generating unit, divided...
by 3,413 Btu/KWh, divided by 1,000 kWh/MWh, and multiplied by
8,760 h/yr (e.g., a 35 percent efficient steam generating unit
with a 100 MW (341 MMBtu/h) fossil-fuel heat input capacity
would have a 310,000 MWh 12 month potential electrical output
capacity[2])” (emphasis added)). Next, we are proposing to add “of
the thermal host facility or facilities” to the definition of
“net-electric output” (i.e., the proposed definition would read
“... the gross electric sales to the utility power distribution
system minus purchased power of the thermal host facility or
facilities on a calendar year basis” (emphasis added).

Finally, consistent with the January 2014 proposal, to
avoid circumvention of the intent of the emission standards
(e.g., by having auxiliary equipment provide steam to the EGU to
increase the output of the EGU and not including the CO₂
emissions in determining the emission rate) and to provide
additional flexibility to the regulated community by
providing through additional compliance options, we are proposing
to amend the definition of a steam generating unit to include
“plus any integrated equipment that provides electricity or
useful thermal output to either the affected facility or
auxiliary equipment” instead in place of the existing language
“plus any integrated combustion turbines and fuel cells.” The
proposed definition would read, “any furnace, boiler, or other
device used for combusting fuel for the purpose of producing
steam (nuclear steam generators are not included) plus any
integrated equipment that provides electricity or useful thermal
output to either the affected facility or auxiliary equipment”
(emphasis added). We are also proposing to add the additional
language to the definition of IGCC in subpart Da (or subpart
TTTT) and stationary combustion turbine in subpart KKKK (or
subpart TTTT).

Although we identify the pollutant we propose to regulate
as GHG, this action proposes to regulate set standards only for
emissions of CO₂. The pollutant we propose to regulate could also
be identified as a broader suite of GHGs. However, and we are not
proposing to regulate set standards for any other GHGs, such as
methane (CH₄) or nitrous oxide (N₂O), because they represent
less than 1 percent of total estimated GHG emissions from fossil
fuel-fired electric power generating units. This is consistent
with the approach that was taken in the proposed standards for
newly constructed EGUs (79 FR 1430, January 8, 2014).

We are also not proposing standards for certain types of
sources. These include modified and reconstructed utility
boilers and IGCC units that were constructed for the purpose of
selling one-third or less of their potential output and 219,000
MWh or less to the grid. These units are not covered under
Subpart Da for any other pollutants but are rather covered as
industrial units boilers under Subpart Db or stationary

Comment [A26]: May want to reword to make
this less confusing. How can the action propose to
regulate only CO₂ but also “identify the pollutant we
propose to regulate” as a broader suite of GHGs?

EPA: The text has been edited to make less confusing.

Comment [A27]: These two sentences together
imply that modified and reconstructed utility boilers
and IGCC units are exempt if they sell less than 1/3 of
their potential output to the grid. It appears from
the “Amended Regulatory Text” TSD, page 43, that
this is not in fact the intention of this rule. Please
clarify what the intent is, both here and in any other
applicable portions of this text.

EPA: The text has been clarified. The amended
regulatory text TSD is intended to show the broadest
applicability the EPA is soliciting comment on. The
TSD will be edits to clarify what the EPA is actually
proposing and soliciting comment on.
combustion turbines under subpart KKKK. We are also not proposing standards for two types of units that are currently covered under Subpart KKKK for other pollutants at this time. The first is stationary combustion turbines that were constructed for the purpose of selling or are selling one-third or less of their potential output or 219,000 MWh or less to the grid. These units only account for a small amount of the CO₂ emissions from fossil-fuel-fired EGUs. The second is modified or reconstructed non-natural gas-fired stationary combustion turbines. Under the proposed approach, applicability with the NSPS for stationary combustion turbines could change on an annual basis depending on electric sales and for facilities burning fuels other than natural gas (e.g., burning backup oil).

B. Emission Standards

In this rulemaking, the EPA is proposing standards of performance for CO₂ emissions from modified and reconstructed EGUs within two categories and several subcategories of affected fossil fuel-fired EGUs.

The proposed standards of performance for the utility boiler and IGCC category are in the form of net energy output-

Oil-fired stationary combustion turbines, including both simple and combined cycle units, are not subject to these proposed standards. These units are typically used only in areas that do not have reliable access to pipeline natural gas (for example, in non-continental areas).
based CO₂ emission limits expressed in units of mass of CO₂ per unit of net energy output (e.g., net electrical output plus 75 percent of the useful thermal output), specifically, in lb CO₂/MWh-net. This emission limit would apply to affected sources upon the effective date of the final action. In this noticedocument, we sometimes refer to “net energy output” as “net output.”

As explained earlier, the proposed standards of performance for natural gas-fired stationary combustion turbines are in the form of a gross output-based emission limit expressed in units of mass of CO₂ per unit of gross energy output, specifically, in lb CO₂/MWh-gross. We also solicit comment on whether we should use a net output-based approach.

The proposed method to calculate compliance is the same as was proposed in the January 8, 2014 proposal. Compliance would be calculated as the sum of the emissions for all operating hours divided by the sum of the useful energy output over a rolling 12-operating-month period. As in the January 2014 proposal, in the alternative, we solicit comment on requiring calculation of compliance on an annual (calendar year) period.

See 79 FR at 1,477/1.
1. Emission Standards for Modified Utility Boilers and IGCC Units

The EPA is proposing that affected modified utility boilers
and IGCC units must meet a standard of performance based on the source’s best potential performance, achieved through a combination of best operating practices and equipment upgrades, as the BSER. The EPA is co-proposing two alternative standards of performance. In the first co-proposed alternative, modified sources would be required to meet a unit-specific numeric emission standard that is two percent lower than the unit’s best demonstrated annual performance during the years from 2002 to the year the modification occurs.

Based on analysis of existing data, the EPA has determined that this standard can be met through a combination of best operating practices and equipment upgrades. In an analysis to determine opportunities for heat rate improvement in the U.S. coal-fired utility power fleet, the EPA found that a total of 6 percent improvement, on average, can be achieved through two types of measures: through best operating practices that have the potential to improve heat rate, on average, by 4 percent, and equipment upgrades that have the potential to improve heat rate, on average, by an additional 2 percent. The EPA also proposes that the unit-specific emission rates that would apply to affected modified utility boilers and IGCC units would be no

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65 Additional detail can be found in the Technical Support Document: “GHG Abatement Measures” (Chapter 2: Heat Rate Improvement at Existing Coal-fired EGUs), available in the rulemaking docket.
more stringent (i.e., no lower) than 1,900 lb CO₂/MWh-net for units with a heat input rating greater than 2,000 MMBtu/h, and no more stringent (i.e., no lower) than 2,100 lb CO₂/MWh-net for units with a heat input rating of 2,000 MMBtu/h or less. These proposed constraints on the stringency of unit-specific emission rate standards are consistent with the emission rate standards proposed in today’s action for reconstructed utility boilers and IGCC units - based on the EPA’s review and analysis of the emissions from the best available generating technology. The EPA is soliciting comment on whether the most stringent standard for modified steam generating units should take into account the current steam cycle of the facility. For example, should large subcritical steam generating units have a most stringent standard that is less stringent (i.e., greater than) 1,900 lb CO₂/MWh-net, which is based on the use of a supercritical steam cycle.

As we discuss in the Legal Memorandum, existing sources that are subject to requirements under an approved CAA section 111(d) plan would remain subject to those requirements after undertaking a modification or reconstruction. Therefore, we are co-proposing a second alternative - that modified sources would be required to meet a unit-specific numeric emission standard

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66 Add cite to legal memo
Legal Memorandum available in rulemaking docket ID: EPA-HQ-OAR-2013-0602.
that would be dependent on the timing of the modification relative to the adoption of a 111(d) plan that covers the source. Specifically, the EPA proposes that sources that modify prior to becoming subject to a CAA section 111(d) plan would be required to meet the same standard described in the first co-proposed alternative – that is, the modified source would be required to meet a unit-specific emission limit determined by the affected source’s best demonstrated historical performance (in the years from 2002 to the time of the modification) with an additional two percent emission reduction. Sources that modify after becoming subject to a CAA section 111(d) plan would be required to meet a unit-specific emission limit that would be determined by the 111(b) permitting implementing authority and would be based on the source’s expected performance after implementation of identified unit-specific energy efficiency improvement opportunities. We seek comment on this proposal that the 111(b) implementing authority would determine the unit-specific emission limit, even when the implementing authority is a state, as opposed to the EPA.

In addition, we solicit comment on alternative ways to determine the best potential performance at affected modified utility boilers and IGCC units. Specifically, we are requesting comment on whether the unit-specific numerical emission standard should be based on the single best annual emission rate (for the
years 2002 to the year when the modification occurs) or the best three consecutive year average emission rate. We also solicit comment on whether there are circumstances where it would not be appropriate to require that the best historical emission rate be made two percent more stringent, or where some other increment of additional stringency should be required.

The EPA also seeks comment on including an additional compliance option for modified utility boilers and IGCC units. Specifically, we seek comment on including uniform emission standards that are similar to the standards proposed for reconstructed utility boilers and IGCC units. Specifically, we seek comment on a standard of 1,900 lb CO₂/MWh-net for modified supercritical sources with a heat input rating of greater than 2,000 MMBtu/h and a standard of 2,100 lb CO₂/MWh-net for all modified subcritical sources and for modified supercritical sources with a heat input rating of 2,000 MMBtu/h or less. The EPA further seeks comment on whether this option should be available only to sources that modify before becoming subject to an approved CAA 111(d) plan or to all modified boilers and IGCC units, regardless of the timing of the modification.

The EPA further solicits comment on whether, in the case of modified utility boilers and IGCC units subject to a CAA section 111(d) plan, there are any circumstances in which the emission limit should be calculated by not including the 2 percent
additional emission reduction based on equipment upgrades. This may, for example, be appropriate in cases where the state plan requires heat rate improvements which improve on the source’s historical performance, or where the source has recently implemented aggressive measures to improve its operating efficiency, and as a result, the additional two percent improvement may be unnecessary or not reasonable.

The EPA also solicits comment on requiring modified utility boilers and IGCC units subject to a CAA section 111(d) plan to take, as their unit-specific emission rate, the lower of (1) the emission rate they are subject to under the section 111(d) plan, or (2) the emission rate that is two percent less than the unit’s best demonstrated annual performance during the years from 2002 to the year the modification occurs. The EPA further seeks comment on whether the time period of the unit’s best demonstrated performance should be limited to the years from 2002 to the time that the unit becomes subject to a CAA 111(d) plan – rather than to the date that the modification occurs. The EPA also seeks comment on whether the time period for best historic performance should be from 2002 to the date of modification – unless the source can provide evidence of significant heat rate improvements that have already been implemented in which case the time period would be from the year of the first heat rate improvement to the modification.
The EPA also seeks comment on whether, and under what circumstances, a modified utility boiler or IGCC unit that modifies prior to becoming subject to a CAA section 111(d) plan should also be allowed to meet an emission limit that is determined from the results of an energy assessment or audit. The EPA also requests comment on whether this approach should be limited to sources that may have voluntarily, or for any other reason, implemented energy efficiency measures in the time period between 2002 and the date of the modification and whether those sources should be required to provide evidence of those energy efficiency improvements.

The EPA also solicits comment on whether we should - as we have proposed in this action - have different standards of performance for modified utility boilers and IGCC units depending on whether a CAA section 111(d) state plan has been submitted (or a federal plan promulgated) or not. On the one hand, a section 111(d) plan may not necessarily impose obligations on a particular unit. On the other hand, such a plan may impose significant obligations on a particular source, and if that source modifies, it may not be as well positioned to implement additional controls. Even so, a state, in developing a 111(d) plan, may choose to confer with its sources to determine whether any expect to modify, and, if any do, take that into account in developing the state plan.
2. Emission Standards for Modified Natural Gas-fired Stationary Combustion Turbines

For affected modified natural gas-fired stationary combustion turbines, this action proposes standards of performance that are based on efficient NGCC technology as the best system of emission reduction (BSER). The emission limits proposed for these sources are 1,000 lb CO₂/MWh-gross for facilities with heat input ratings greater than 850 MMBtu/h, and 1,100 lb CO₂/MWh-gross for facilities with heat input ratings of 850 MMBtu/h or less.\(^67\)

In the companion rulemaking proposing emission guidelines under CAA section 111(d) for CO₂ emissions from existing affected EGUs, the EPA is proposing that an existing source that becomes subject to requirements under section 111(d) will continue to be subject to those requirements even after it undertakes a modification or reconstruction. This is also discussed in greater detail in the ‘Legal Memorandum’\(^68\). Under this interpretation, a modified or reconstructed source would be subject to both (1) the section 111(d) requirements that it had previously been subject to and (2) the modified source or

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\(^67\) This subcategorization of stationary combustion turbines is consistent with the subcategories used in the combustion turbine (subpart KKKK) criteria pollutant NSPS. The size limit of 850 MMBtu/h corresponds to approximately 100 MWe.

\(^68\) Add cite to legal memo
reconstructed source standard under 111(b) proposed in this rulemaking.

The EPA also solicits comment on an optional alternative method for calculating the emission limit that would be applicable to an affected modified natural gas-fired stationary combustion turbine after that unit becomes subject to a CAA section 111(d) plan. The EPA specifically seeks comment on the option of allowing the affected source to meet a unit-specific emission limit that is determined by the 111(b) permitting implementing authority from an assessment to identify energy efficiency improvement opportunities for the affected source.

3. Emission Standard for Reconstructed EGUs

Reconstructed fossil fuel-fired boilers and IGCC units with a heat input rating that is greater than 2,000 MMBtu/h would be required to meet a standard of 1,900 lb CO₂/MWh-net.

Reconstructed fossil fuel-fired utility boilers and IGCC units with a heat input rating that is 2,000 MMBtu/h or less would be required to meet a standard of 2,100 lb CO₂/MWh-net.

Reconstructed natural gas-fired stationary combustion turbines with a heat input rating greater than 850 MMBtu/h would be required to meet a standard of 1,000 lb CO₂/MWh-gross.

Reconstructed combustion turbines with a heat input rating or 850 MMBtu/h or less would be required to meet a standard of 1,100 lb CO₂/MWh-gross.
While the EPA is proposing these standards of performance, we are also taking comment on a range of potential emission limits. Specifically, we solicit comment on the following emission limit ranges:

1. for reconstructed fossil fuel-fired boilers and IGCC units with a heat input rating that is greater than 2,000 MMBtu/h, a range of 1,700 – 2,100 lb CO₂/MWh-net;
2. for reconstructed fossil fuel-fired boilers and IGCC units with a heat input rating of 2,000 MMBtu/h or less, a range of 1,900 – 2,300 lb CO₂/MWh-net;
3. for reconstructed stationary combustion turbines with a heat input rating greater than 850 MMBtu/h, a range of 950 – 1,100 lb CO₂/MWh-gross; and
4. for reconstructed stationary combustion turbines with a heat input rating of 850 MMBtu/h or less, a range of 1,000 – 1,200 lb CO₂/MWh-gross;

We also solicit comment on whether: (1) the standards for utility boilers and IGCC units should be subcategorized by primary fuel type, (2) the small utility boiler and IGCC unit subcategory should be limited to utility boilers so that all IGCC units would be in the large subcategory regardless of size, or if there are sufficient alternate compliance technologies (e.g., co-firing natural gas) that the small unit subcategory is unnecessary and should be eliminated so that those sources would
be required to meet the same emission standard as large utility boilers and IGCC units, and (3) an annual short term performance test should be required for stationary combustion turbines in addition to the 12-operating-month rolling average standard. Requiring an initial and annual short term compliance test that is numerically more stringent than the 12-operating month standard for modified and reconstructed stationary combustion turbines would insure that efficient stationary combustion turbines are installed and properly maintained. The less stringent 12-month rolling average standard would be set at a level that would account for operating conditions where the emission rate is higher than design conditions.

3. Net Output

We are proposing standards for modified and reconstructed units as net output emission rates. We are also requesting comment on using either gross output standards or adjusted gross output based standards in the final rule. See the TSD for more details.\(^69\)

C. Startup, Shutdown and Malfunction Requirements

\(^69\) In the January 8, 2014 proposal for new sources, we proposed standards as gross output emission rates, See 79 FR 1,447\(\text{\footnote{44}}\) and 1,448\(\text{\footnote{44}}\). In the rulemaking for existing sources that we are proposing concurrently with this rulemaking, we are proposing emission guidelines that call for state standards as net output emission rates (but seek comment on gross output-based emission rates).
Consistent with the January 8, 2014, proposal, we are proposing the standards in this rule apply at all times, including during periods of startup and shutdown. We are also proposing malfunction and affirmative defense provisions consistent with the January 8, 2014, proposal. This section provides a summary of the requirements. For additional detail, see 79 FR 1430 (January 8, 2014) at 1,448/3 – 1,450/2 and the TSD.

1. Startups and shutdowns

Consistent with Sierra Club v. EPA, the EPA is proposing standards in this rule that apply at all times, including during startups and shutdowns. In proposing the standards in this rule, the EPA has taken into account startup and shutdown periods. In the compliance calculation, periods of startup and shutdown are included as periods of partial load. The proposed method to calculate compliance is to sum the emissions for all operating hours and to divide that value by the sum of the electrical energy output and useful thermal energy output, where applicable for CHP EGUs, over a rolling 12-operating-month period. The EPA is proposing that sources incorporate in their compliance determinations emissions from all periods, including startup or shutdown, that fuel is combusted and emissions monitors are not.

Comment [A30]: Given the recent court decision that struck down affirmative defense, what does EPA plan to do here?

EPA Response: Text has been edited.
out-of-control, as well as all power produced over the periods of emissions measurements. Given that the duration of startup or shutdown periods are expected to be small relative to the duration of periods of normal operation and that the fraction of power generated during periods of startup or shutdown is expected to be very small during startup or shutdown periods, the impact of these periods on the total average is expected to be minimal.

2. Malfunctions

Note: A court decision this morning related to the Portland Cement MACT may impact the way the agency addresses affirmative defense. Once we have determined how the ruling impacts our general affirmative defense policy, we will modify the preamble accordingly.

Periods of startup, normal operations, and shutdown are all predictable and routine aspects of a source’s operations. However, by contrast, malfunction is defined as “any sudden, infrequent, and not reasonably preventable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner. Failures that are caused in part by poor maintenance or careless operation are not malfunctions.” (40 CFR 60.2). The EPA has determined that section 111 does not require that emissions that occur during periods of malfunction be factored into development of CAA section 111 standards. Nothing in CAA section 111 or in case law
requires that the EPA anticipate and account for the innumerable types of potential malfunction events in setting emission standards. CAA section 111 provides that the EPA set standards of performance which reflect the degree of emission limitation achievable through “the application of the best system of emission reduction” that the EPA determines is adequately demonstrated. A malfunction is a failure of the source to perform in a “normal or usual manner” and no statutory language compels EPA to consider such events in setting standards based on the “best system of emission reduction.” The “application of the best system of emission reduction” is more appropriately understood to include operating units in such a way as to avoid malfunctions.

Further, accounting for malfunctions in setting emission standards would be difficult, if not impossible, given the myriad different types of malfunctions that can occur across all sources in the category and given the difficulties associated with predicting or accounting for the frequency, degree, and duration of various malfunctions that might occur. As such, the performance of units that are malfunctioning is not “reasonably” foreseeable. See, e.g., Sierra Club v. EPA, 167 F.3d 658, 662 (D.C. Cir. 1999) (“The EPA typically has wide latitude in determining the extent of data-gathering necessary to solve a problem. We generally defer to an agency's decision to proceed...
on the basis of imperfect scientific information, rather than to 'invest the resources to conduct the perfect study.'" See also, Weyerhaeuser v Costle, 590 F.2d 1011, 1058 (D.C. Cir. 1978) ("In the nature of things, no general limit, individual permit, or even any upset provision can anticipate all upset situations. After a certain point, the transgression of regulatory limits caused by 'uncontrollable acts of third parties,' such as strikes, sabotage, operator intoxication or insanity, and a variety of other eventualities, must be a matter for the administrative exercise of case-by-case enforcement discretion, not for specification in advance by regulation."). In addition, emissions during a malfunction event can be significantly higher than emissions at any other time of source operation and thus accounting for malfunctions could lead to standards that are significantly less stringent than levels that are achieved by a well-performing non-malfunctioning source. It is reasonable to interpret section 111 to avoid such a result. The EPA’s approach to malfunctions is consistent with section 111 and is a reasonable interpretation of the statute.

In the event that a source fails to comply with the applicable CAA section 111 standards as a result of a malfunction event, the EPA would determine an appropriate response based on, among other things, the good faith efforts of the source to minimize emissions during malfunction periods,
including preventative and corrective actions, as well as root
cause analyses to ascertain and rectify excess emissions. The
EPA would also consider whether the source's failure to comply
with the CAA section 111 standard was, in fact, “sudden,
infrequent, not reasonably preventable” and was not instead
“caused in part by poor maintenance or careless operation.” 40
CFR § 60.2 (definition of malfunction).

Further, to the extent the EPA files an enforcement action
against a source for violation of an emission standard, the
source can raise any and all defenses in that enforcement action
and the federal district court will determine what, if any,
relief is appropriate. The same is true for citizen enforcement
actions. Similarly, the presiding officer in an administrative
proceeding can consider any defense raised and determine whether
administrative penalties are appropriate.

In several prior rules, the EPA had included an affirmative
defense to civil penalties for violations caused by malfunctions
in an effort to create a system that incorporates some
flexibility, recognizing that there is a tension, inherent in
many types of air regulation, to ensure adequate compliance
while simultaneously recognizing that despite the most diligent
of efforts, emission standards may be violated under
circumstances entirely beyond the control of the source.
Although the EPA recognized that its case-by-case enforcement
discretion provides sufficient flexibility in these circumstances, it included the affirmative defense to provide a more formalized approach and more regulatory clarity. See Weyerhaeuser Co. v. Costle, 590 F.2d 1011, 1057-58 (D.C. Cir. 1978) (holding that an informal case-by-case enforcement discretion approach is adequate); but see Marathon Oil Co. v. EPA, 564 F.2d 1253, 1272-73 (9th Cir. 1977) (requiring a more formalized approach to consideration of “upsets beyond the control of the permit holder.”). Under the EPA’s regulatory affirmative defense provisions, if a source could demonstrate in a judicial or administrative proceeding that it had met the requirements of the affirmative defense in the regulation, civil penalties would not be assessed. Recently, the United States Court of Appeals for the District of Columbia Circuit vacated such an affirmative defense in one of the EPA’s Section 112(d) regulations. NRDC v. EPA, No. 10-1371 (D.C. Cir. April 18, 2014) 2014 U.S. App. LEXIS 7281 (vacating affirmative defense provisions in Section 112(d) rule establishing emission standards for Portland cement kilns). The court found that the EPA lacked authority to establish an affirmative defense for private civil suits and held that under the CAA, the authority to determine civil penalty amounts lies exclusively with the courts, not the EPA. Specifically, the Court found: “As the language of the statute makes clear, the courts determine, on a
case-by-case basis, whether civil penalties are ‘appropriate.’”

See NRDC, 2014 U.S. App. LEXIS 7281 at *21 (“[U]nder this statute, deciding whether penalties are ‘appropriate’ in a given private civil suit is a job for the courts, not EPA.”). In light of NRDC, the EPA is not including a regulatory affirmative defense provision in this rulemaking. As explained above, if a source is unable to comply with emissions standards as a result of a malfunction, the EPA may use its case-by-case enforcement discretion to provide flexibility, as appropriate. Further, as the D.C. Circuit recognized, in an EPA or citizen enforcement action, the court has the discretion to consider any defense raised and determine whether penalties are appropriate. Cf. NRDC, 2014 U.S. App. LEXIS 7281 at *24. (arguments that violation were caused by unavoidable technology failure can be made to the courts in future civil cases when the issue arises). The same logic applies to EPA administrative enforcement actions.

Periods of startup, normal operations, and shutdown are all predictable and routine aspects of a source’s operations. However, by contrast, malfunction is defined as “any sudden,

71 The court’s reasoning in NRDC focuses on civil judicial actions. The Court noted that “EPA’s ability to determine whether penalties should be assessed for Clean Air Act violations extends only to administrative penalties, not to civil penalties imposed by a court.” Id.
infrequent, and not reasonably preventable failure of air
pollution control equipment, process equipment, or a process to
operate in a normal or usual manner. Failures that are caused in
part by poor maintenance or careless operation are not
malfunctions.” (40 CFR 60.2). The EPA has determined that
section 111 does not require that emissions that occur during
periods of malfunction be factored into development of CAA
section 111 standards. Nothing in CAA section 111 or in case law
requires that the EPA anticipate and account for the innumerable
types of potential malfunction events in setting emission
standards. CAA section 111 provides that the EPA set standards
of performance which reflect the degree of emission limitation
achievable through “the application of the best system of
emission reduction” that the EPA determines is adequately
demonstrated. Applying the concept of “the application of the
best system of emission reduction” to periods during which a
source is malfunctioning presents difficulties. The “application
of the best system of emission reduction” is more appropriately
understood to include operating units in such a way as to avoid
malfunctions. The EPA’s approach to malfunctions is consistent
with section 111 and is a reasonable interpretation of the
statute.

In the event that a source fails to comply with the
applicable CAA section 111 standards as a result of a
malfunction event, the EPA would determine an appropriate
response based on, among other things, the good faith efforts of
the source to minimize emissions during malfunction periods,
including preventative and corrective actions, as well as root
cause analyses to ascertain and rectify excess emissions. The
EPA would also consider whether the source's failure to comply
with the CAA section 111 standard was, in fact, “sudden,
infrequent, not reasonably preventable” and was not instead
“caused in part by poor maintenance or careless operation.” 40
CFR section 60.2 (definition of malfunction).

Finally, the EPA recognizes that even equipment that is
properly designed and maintained can sometimes fail and that
such failure can sometimes cause a violation of an emission
standard. The EPA is therefore proposing to add an affirmative
defense to civil penalties for violations of emission standards
in this rule that are caused by malfunctions. (See 40 CFR
60.10042 (defining “affirmative defense” to mean, in the context
of an enforcement proceeding, a response or defense put forward
by a defendant, regarding which the defendant has the burden of
proof, and the merits of which are independently and objectively
evaluated in a judicial or administrative proceeding.) We also
are proposing other regulatory provisions to specify the
elements that are necessary to establish this affirmative
defense. The proposed criteria are designed in part to ensure
that the affirmative defense is available only where the event that causes a violation of the emission standard meets the narrow definition of malfunction in 40 CFR 60.2. The proposed criteria also are designed to ensure that steps are taken to correct the malfunction, to minimize emissions and to prevent future malfunctions. In any judicial or administrative proceeding, the Administrator may challenge the assertion of the affirmative defense and, if the respondent has not met its burden of proving all of the requirements in the affirmative defense, appropriate penalties may be assessed in accordance with section 113 of the CAA (see also 40 CFR 22.27).

D. Continuous Monitoring Requirements

We are proposing the same monitoring requirements for modified and reconstructed sources as were proposed for new sources in the January 8, 2014, proposal. This section provides a summary of the requirements. For additional detail, see 79 FR at 1,450/2 and 1,451/2 and the TSB.

Today’s proposed rule would require owners or operators of EGUs that combust solid fuel to install, certify, maintain, and operate continuous emission monitoring systems (CEMS) to measure CO₂ concentration, stack gas flow rate, and (if needed) stack gas moisture content in accordance with 40 CFR Part 75, in order to determine hourly CO₂ mass emissions rates (tons/h).
The proposed rule would allow owners or operators of EGUs that burn exclusively gaseous or liquid fuels to install fuel flow meters as an alternative to CEMS and to calculate the hourly CO₂ mass emissions rates using Equation G-4 in Appendix G of Part 75. To implement this option, hourly measurements of fuel flow rate and periodic determinations of the gross calorific value (GCV) of the fuel are also required, in accordance with Appendix D of Part 75.

In addition to requiring monitoring of the CO₂ mass emission rate, the proposed rule would require EGU owners or operators to monitor the hourly unit operating time and “gross output”, expressed in megawatt hours (MWh). The gross output includes electrical output plus any mechanical output, plus 75 percent of any useful thermal output.

The proposed rule would require EGU owners or operators to prepare and submit a monitoring plan that includes both electronic and hard copy components, in accordance with 40 CFR parts §§ 75.53(g) and (h). Further, all monitoring systems used to determine the CO₂ mass emission rates would have to be certified according to § 75.20 and section 6 of Part 75, Appendix A within the 180-day window of time allotted under § 75.4(b), and would be required to meet the applicable on-going quality assurance procedures in Appendices B and D of Part 75.
The proposed rule would require only those operating hours in which valid data are collected and recorded for all of the parameters in the CO₂ mass emission rate equation to be used for compliance purposes. Additionally for EGUs using CO₂ CEMS, only unadjusted stack gas flow rate values would be used in the emissions calculations. In this proposal, Part 75 bias adjustment factors (BAFs) would not be applied to the flow rate data. These restrictions on the use of Part 75 data for Part 60 compliance are consistent with previous NSPS regulations and revisions.

Certain variations from and additions to the basic Part 75 monitoring would be required and are detailed in the January 2014 proposal (see 79 FR at 1,451/1).

Special compliance provisions for units with common stack or multiple stack configurations, consistent with § 60.13(g), would be required and are detailed in the January 2014 proposal (see 79 FR at 1,451/1 - 1,451/2).

The proposed rule would require 95 percent of the operating hours in each compliance period (including the compliance periods for the intermediate emission limits) to be valid hours, i.e., operating hours in which quality-assured data are collected and recorded for all of the parameters used to calculate CO₂ mass emissions. EGU owners or operators would have the option to use backup monitoring systems, as provided in §§
75.10(e) and 75.20(d), to help meet this proposed data capture requirement.

E. Emissions Performance Testing Requirements

We are proposing the same emissions performance testing requirements for modified and reconstructed sources as were proposed for new sources in the January 8, 2014 proposal. This section provides a summary of the requirements. For additional detail, see 79 FR at 1,451/2 – 1,451/3 and the TSD.

In accordance with § 75.64(a), the proposed rule would require an EGU owner or operator to begin reporting emissions data when monitoring system certification is completed or when the 180-day window in § 75.4(b) allotted for initial certification of the monitoring systems expires (whichever date is earlier). The initial performance test would consist of the first 12-operating-months of data, starting with the month in which emissions are first required to be reported. The initial 12-operating-month compliance period would begin with the first month of the first calendar year of EGU operation in which the facility exceeds the capacity factor applicability threshold.

The traditional 3-run performance tests (i.e., stack tests) described in § 60.8 would not be required for this rule. Following the initial compliance determination, the emission standard would be met on a 12-operating-month rolling average basis.
F. Continuous Compliance Requirements

We are proposing the same continuous compliance requirements for modified and reconstructed sources as were proposed for new sources in the January 8, 2014 proposal. This section provides a summary of the requirements. For additional detail, see 79 FR at 1,451/3 and the TSD.

Today’s proposed rule specifies that compliance with the mass emissions rate limits would be determined on a 12-operating-month rolling average basis, updated after each new operating month. For each 12-operating-month compliance period, quality-assured data from the certified Part 75 monitoring systems would be used together with the gross output over that period of time to calculate the average CO₂ mass emissions rate.

The proposed rule specifies that the first operating month included in the initial 12-operating-month compliance period would be the month in which reporting of emissions data is required to begin under § 75.64(a), i.e., either the month in which monitoring system certification is completed or the month in which the 180-day window allotted to finish certification testing expires (whichever month is earlier).

We are proposing that initial compliance with the applicable emissions limit in kg/MWh be calculated by dividing the sum of the hourly CO₂ mass emissions values by the total gross output for the 12-operating-month period. Affected EGUs
would continue to be subject to the standards and maintenance requirements in the section 111 regulatory general provisions contained in 40 CFR part 60, subpart A.

G. Notification, Recordkeeping and Reporting Requirements

We are proposing the same notification, recordkeeping and reporting requirements for modified and reconstructed sources as that were proposed for new sources in the January 8, 2014, proposal. This section provides a summary of the requirements.

For additional detail, see 79 FR at 1,451/3 and 1,452/3 and the TSD.

Today’s proposed rule would require an EGU owner or operator to comply with the applicable notification requirements in § 75.61, §§ 60.7(a)(1) and (a)(3), and § 60.19 and § 75.61. The proposed rule would also require the applicable recordkeeping requirements in subpart F of Part 75 to be met.

For EGUs using CEMS, the data elements that would be recorded include, among others, hourly CO₂ concentration, stack gas flow rate, stack gas moisture content (if needed), unit operating time, and gross electric generation.

For EGUs that exclusively combust liquid and/or gaseous fuel(s) and elect to determine CO₂ emissions using Equation G-4 in Appendix G of Part 75, the key data elements in subpart F that would be recorded include hourly fuel flow rates, fuel usage times, fuel GCV, gross electric generation.
The proposed rule would require EGU owners or operators to keep records of the calculations performed to determine the total CO₂ mass emissions and gross output for each operating month. Records would be kept of the calculations performed to determine the average CO₂ mass emission rate (kg/MWh) and the percentage of valid CO₂ mass emission rates in each compliance period. The proposed rule would also require records to be kept of calculations performed to determine site-specific carbon-based F-factors for use in Equation G-4 of Part 75, Appendix G (if applicable).

The proposed rule would require all affected EGU owners/operators to submit quarterly electronic emissions reports in accordance with subpart G of Part 75. The proposed rule would require these reports to be submitted using the ECMPS Client Tool. Except for a few EGUs that may be exempt from the Acid Rain Program (e.g., oil-fired units), this is not a new reporting requirement. Sources subject to the Acid Rain Program are already required to report the hourly CO₂ mass emission rates that are needed to assess compliance with today’s rule.

Additionally, in the proposed rule and as part of an Agency-wide effort to streamline and facilitate the reporting of environmental data, the rule would require that quarterly electronic “excess emissions” reports be submitted using ECMPS, within 30 days after the end of each quarter. Reporting the
percentage of valid CO₂ mass emission rates is necessary to demonstrate compliance with the requirement to obtain valid data for 95 percent of the operating hours in each compliance period. Any excess emissions that occur during the quarter would be identified.

For EGU owners or operators that would assert an affirmative defense for a failure to meet a standard due to malfunction, the owner or operator must follow the reporting requirements for affirmative defense. The report to the Administrator, with all necessary supporting documentation, must be submitted on the same schedule as the next quarterly report required after the initial occurrence of the violation of the relevant standard (which may be the end of any applicable averaging period).

IV. Rationale for Reliance on Rational Basis to Regulate GHG from Fossil Fuel-fired EGUs

A. Rational Basis and Endangerment Finding

In the January 2014 proposal, the EPA proposed that, in order to regulate GHG from new fossil fuel-fired EGUs, the EPA needed a rational basis, but that CAA section 111 did not require an endangerment finding. The EPA further proposed that even if section 111 did require such a finding, the EPA’s rational basis would qualify as one. The EPA expects to finalize the January 2014 proposal by the time that it finalizes this
proposed rulemaking for affected modified and reconstructed fossil fuel-fired EGUs, and in that event, the EPA would not be required to further address the rational basis or endangerment finding in this rulemaking.

However, because this rulemaking is a separate action from the January 2014 proposal, the EPA is making the same proposal – that the EPA has a rational basis for this rulemaking, and that no endangerment finding is required, but that if one is, the EPA’s rational basis would qualify as one – which it made in the January 2014 proposal. See 79 FR at 1,452/3 –through 1,456/1; see the TSD for more detail.

B. Source Categories

This proposal addresses the same two source categories – fossil fuel-fired steam generating units (utility boilers and IGCC units) and natural gas-fired stationary combustion turbines – that were addressed by the January 2014 proposal. In the January 2014 proposal, the EPA included a proposal and co-proposal for the treatment of the two affected source categories, and for how the regulatory requirements applicable to these source categories would be codified in 40 CFR part 60. Specifically, the EPA proposed to create subcategories within each category, and to codify the regulatory requirements for each subcategory in 40 CFR part 60, subparts Da and KKKK, respectively. In addition, the EPA co-proposed to combine the
two categories for purposes of regulating the CO₂ emissions, and to codify all the CO₂ regulatory requirements in a new subpart, TTTT.

As noted, the EPA expects to finalize the January 2014 proposal by the time that it finalizes this proposed rulemaking for modified and reconstructed fossil fuel-fired EGUs. It is the EPA’s intent that the approach for categorization and codification will be the same in the final action for this proposal as is finalized for the January 2014 proposal. However, because this rulemaking is a separate action from the January 2014 proposal, the EPA is making the same proposal and co-proposal with regard to categories and codification for modified and reconstructed sources that it made with regard to new construction sources in the January 2014 proposal. That is, the EPA proposes to create subcategories within each category and to codify the regulatory requirements in 40 CFR part 60, subparts Da and KKKK, respectively; and in addition, the EPA co-proposes to combine the two categories for purposes of regulating CO₂ emissions, and to codify all the CO₂ regulatory requirements in a new subpart, TTTT. See 79 FR at 1,452/3 –through 1,454/4; See the TSD for more details.

V. Rationale for Applicability Requirements

The rationale for several of the proposed applicability requirements for modified and reconstructed sources is the same
as that in the January 2014 proposal. This section provides a summary of the rationale for these requirements along with rationale for differences with the applicability included in the January 2014 proposal. In addition, we are soliciting comment on multiple alternative approaches to the applicability criteria. In the January 2014 proposal, we also solicit comment on various issues concerning, and different approaches to, the applicability requirements for steam generating units and combustion turbines. For additional detail, see 79 FR at 1,459/1–1,461/2 and the TSD.

In today’s rulemaking, we propose that standards of performance apply to a facility if the facility supplies more than one-third of its potential electric output and more than 219,000 MWh net electric output to the grid per year. (We refer to a facility’s sale of more than one-third of its potential electric output as the one-third sales criterion, and we refer to the amount of potential electric output supplied to a utility power distribution system, expressed in MWh, as the capacity factor.) This proposed definition does not explicitly exclude

\[\text{For additional detail, see 79 FR at 1,459/1–1,461/2 and the TSD.}\]
simple cycle combustion turbines, but as a practical matter, it would exclude most of them because the vast majority of simple cycle turbines sell less than one-third of their potential electric output. The few simple-cycle combustion turbines that sell more than one-third of their potential electric output to the grid would be subject to the proposed standards of performance.

The following four proposed applicability criteria are consistent with the January 2014 proposal. First, this proposal includes within the definition of a utility boiler, IGCC unit, and stationary combustion turbine that is subject to the proposed requirements, any integrated device that provides electricity or useful thermal output to the boiler, the stationary combustion turbine or to power auxiliary equipment. The rationale behind including integrated equipment recognizes that the integrated equipment may be a type of combustion unit that emits GHGs, and that it is important to assure that those GHG emissions are included as part of the overall GHG emissions from the affected source.

Second, we are also proposing a different definition of potential electric output from the current definition that determines the potential electric output (in MWh on an annual basis) considering only the design heat input capacity of the facility and does not account for efficiency. It assumes a 33
percent net electric efficiency, regardless of the actual efficiency of the facility. Therefore, we are proposing a definition of potential electric output that allows the source the option of calculating its potential electric output on the basis of its actual design electric output efficiency on a net output basis, as an alternative to the default one-third value.

Third, we are proposing to apply the one-third sales criterion on a rolling three year basis instead of an annual basis for stationary combustion turbines for multiple reasons. First, extending the period to three years would ensure that the CO2 standards apply only to intermediate and base load EGUs by allowing facilities intended to generally operate at low capacity factors (e.g. simple cycle turbines that generally sell less than one-third of their potential electric output) to avoid applicability. Second, only 0.2 percent of existing simple cycle turbines had a three-year average capacity factor of greater than one-third between 2000 and 2012.

In today’s action Finally, we propose that if CHP facilities meet the general applicability criteria they should be subject to the same requirements as electric-only generators. However, one potential issue that we have identified is inequitable applicability to third-party CHP developers compared to CHP facilities owned by the facility using the thermal output from the CHP facility. We are therefore proposing to add “of the
thermal host facility or facilities” to the definition of net-electric output for qualifying CHP facilities (i.e., the clause would read, “the gross electric sales to the utility power distribution system minus purchased power of the thermal host facility or facilities on a calendar year basis” (emphasis added)). This would make applicability consistent for both facility-owned CHP and third-party-owned CHP.

The rationale for following applicability criteria are different than the January 2014 proposal. To clarify that existing boiler and IGCC facilities would continue to be included in 111(d) state programs regardless of their actual electric sales or fossil fuel use, we are deleting the criteria that to be considered and EGU the facility must (1) actually sell 1/3 of their potential electric output and 219,000 MWh on an annual basis and (2) the applicability exemption for facilities than burn fossil fuel for 10 percent or less of the total heat input during a 3 year rolling average period. The sales criteria exemption was intended to exempt low capacity factor facilities since they would have additional difficulties meeting the standards proposed in the January 2014 proposal. However, the proposed standards for boilers and IGCC facilities in the rulemaking are less stringent and are achievable by low capacity factor facilities so the applicability exemption would not be applicable. The low fossil use exemption was designed to
exempt facilities that are capable of combusting fossil fuel, but burn primarily non fossil fuels. These facilities (e.g., wood-fired EGUs) typically are inherently less efficient than fossil fuel-fired EGUs, and we are soliciting comment on if we should subcategorize boilers and IGCC facilities that fossil fuel consists of 10 percent or less of the heat input during. In the event we establish a subcategory, should the heat input be determined on an annual or 3 year rolling period and should the standard be an alternate numerical limit or "no emission standard".

In the January 2014 proposal, we also solicit comment on various issues concerning, and different approaches to, the applicability requirements for steam generating units and combustion turbines. For additional detail, see 79 FR 1,459 through 1,461. We are soliciting comment on additional approaches to address potential unintended negative environmental impacts and to address issues concerning how the general applicability of the 111(b) NSPS potentially impacts the 111(d) rulemaking since only EGUs that would be included under

Requests for comment in the January 2014 proposal regarding the appropriateness of certain applicability requirements that are based on a source’s operations do not apply to this proposed rulemaking. Whereas newly constructed sources would not have a history of operating, in this rulemaking, the affected sources that would be undertaking modifications or reconstructions do have an operating history.
the 111(b) applicability if they were new, modified or reconstructed are included in the state 111(d) goals.

We are also proposing a different definition of potential electric output from the current definition that determines the potential electric output (in MWh on an annual basis) considering only the design heat input capacity of the facility and does not account for efficiency. It assumes a 33 percent net electric efficiency, regardless of the actual efficiency of the facility. Therefore, we are proposing a definition of potential electric output that allows the source the option of calculating its potential electric output on the basis of its actual design electric output efficiency on a net output basis, as an alternative to the default one third value.

In addition, we are proposing to limit the applicability of the standards to facilities where the heat input is comprised of more than 10.0 percent fossil fuel on a three-year rolling average basis. Facilities that fall below this 10.0 percent threshold more closely resemble the non-fossil fuel-fired boilers and stationary combustion turbines that are not covered by today’s proposed rule, than they do the fossil fuel-fired boilers and stationary combustion turbines that are covered by this rule. We, therefore, have concluded that it is not appropriate to subject facilities that primarily burn non-fossil
fuels, but also co-fire a limited amount of fossil fuel, to the standards in today's proposal.

In today's action, we propose that if CHP facilities meet the general applicability criteria they should be subject to the same requirements as electric-only generators. However, one potential issue that we have identified is inequitable applicability to third-party CHP developers compared to CHP facilities owned by the facility using the thermal output from the CHP facility. We are therefore proposing to add “of the thermal host facility or facilities” to the definition of net electric output for qualifying CHP facilities (i.e., the clause would read, “the gross electric sales to the utility power distribution system minus purchased power of the thermal host facility or facilities on a calendar year basis” (emphasis added)). This would make applicability consistent for both facility-owned CHP and third-party-owned CHP.

This proposal includes within the definition of a utility boiler, IGCC unit, and stationary combustion turbine that is subject to the proposed requirements, any integrated device that provides electricity or useful thermal output to the boiler, the stationary combustion turbine or to power auxiliary equipment. The rationale behind including integrated equipment recognizes that the integrated equipment may be a type of combustion unit that emits GHGs, and that it is important to ensure that those
VI. Rationale for Emission Standards for Reconstructed Fossil Fuel-Fired Utility Boilers and IGCC Units.

A. Overview

In this section, we explain our rationale for emission standards for reconstructed fossil fuel-fired utility boiler and IGCC units, which are based on our proposal that the most efficient generating technology is the BSER for these types of units.

CAA section 111(b)(1)(B) authorizes the EPA to promulgate “standards of performance” for new sources, including modified and reconstructed sources. The CAA directs that standards of performance must consist of emission limits that are based on the “best system of emission reduction ... adequately demonstrated,” taking into account cost and other factors. In this manner, CAA section 111 provides that the EPA’s central task is to identify the BSER.

Over a 40-year period, the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit or Court) has issued a number of decisions interpreting this CAA provision, including
its component elements.74 Consistent with this case law, 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 EPA must consider the amount of emissions reductions that the system would generate.
- The costs of the system must be reasonable. The EPA may consider the costs on the source level, the industry-wide 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.75

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75 As discussed in the January 2014 Proposal, the D.C. Circuit’s case law formulates the cost consideration in various ways: the costs must not be “exorbitant[]”, Essex Chemical Corp. v. Ruckelshaus, 486 F.2d 427, 433 (D.C. Cir. 1973), see Lignite Energy Council v. EPA, 198 F.3d 930, 933 (D.C. Cir. 1999); “greater than the industry could bear and survive,” Portland Cement Ass’n–Association v. EPA, 513 F.2d 506, 508 (D.C. Cir. 1975); or “excessive” or “unreasonable.” Sierra Club v. Costle, 657 F.2d 298, 343 (D.C. Cir. 1981). In the January 2014 Proposal, EPA stated that “these various formulations of the cost standard ... are synonymous,” and, for convenience, EPA used “reasonableness” as the formulation. EPA takes the same approach in this proposal.
The EPA must also consider that CAA section 111 is designed to promote the deployment, development and implementation of technology.\footnote{76 See discussion of case law and legislative history in the January 2014 proposal. 79 Fed. Reg. 1430, 1465 (cols. 1-2) (January 8, 2014).} Other considerations are also important, including that the EPA must also consider energy impacts, and, as with costs, may consider them on the source level and on the nationwide structure of the power sector over time. Importantly, 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. The EPA discussed the CAA requirements and Court interpretations of the BSER at length in the January 2014 proposal, 79 FR \textsuperscript{1462/1 –through 1467/3}, and incorporates by reference that discussion in this rulemaking.\footnote{77 It should be noted that in one of the earliest cases, \textit{Essex Chemical Corp. v. Ruckelshaus}, in 1973, the Court stated that because the standard must be “achievable,” the emission limits must be technically feasible, and added that “[a]n adequately demonstrated system 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.” \textit{Essex Chemical Corp. v. Ruckelshaus}, 486 F.2d at 427. This case law may be read to treat technical feasibility as the measure for whether the standard of performance is “achievable,” not as a criteria for whether the system of emission reduction is the “best system of emission reduction … adequately demonstrated.” However, for convenience, we may refer to technical feasibility as another of the criteria for the BSER.}
It should be noted at the outset that the EPA determined that reconstructions are a type of construction, and therefore subject to section 111(b), as part of the 1975 framework regulations, and the EPA is not re-opening that determination.\textsuperscript{78} The EPA also defined reconstructions in those regulations, and the EPA is not reopening that definition in this rulemaking. These provisions have two main specifications: (1) that reconstruction occurs upon replacement of components if the fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct an entirely new comparable facility, and, (2) that it is technologically and economically feasible for the facility to comply with the applicable standards of performance after the replacements. 40 CFR part 60.15. These reconstruction provisions have not been amended since originally promulgated in 1975, and have been implemented for numerous source categories.

B. Identification of Best System of Emissions Reduction

The EPA evaluated seven different control technology configurations as potentially representing the BSER for reconstructed fossil fuel-fired boiler and IGCC EGUs: (1) the use of partial carbon capture and storage (CCS), (2) conversion to (or co-firing with) natural gas, (3) the use of combined heat

\textsuperscript{78}40 FR 58417-58418, December 16, 1975 (final NSPS modification, notification, and reconstruction provisions).
and power (CHP), (4) hybrid power plants (5) reductions in
generation associated with dispatch changes, renewable
generation, and demand side energy efficiency,(6) efficiency
improvements achieved through the use of the most efficient
generation technology, and (7) efficiency improvements achieved
through a combination of best operating practices and equipment
upgrades.79

We discuss each of these alternatives below, and explain
why we propose that for reconstructed fossil fuel-fired boiler
and IGCC EGUs the most efficient generating technology qualifies
as the BSER.

1. Partial CCS

We considered the implementation of partial CCS as the BSER
at affected reconstructed utility boilers and IGCC units. In the
January 8, 2014 proposal (79 FR 1430), the EPA found that, for
new units, partial CCS has been adequately demonstrated and is
technically feasible; it can be implemented at costs that are
not unreasonable; it provides meaningful emission reductions;
its implementation will serve to promote further development and
deployment of the technology; and it would not have a

79 Note that we also evaluated these seven different technology
configurations as potentially representing BSER for modified
utility boilers and IGCC units. The subsequent discussion of
each of these is also applicable for that evaluation as well.
noted in the January 2014 proposal that most of the relatively few new projects that are in the development phase are already planning to implement CCS, so that partial CCS was consistent with current industry trends.

Partial CCS has been demonstrated at some existing EGUs. It has been demonstrated at a large pilot scale (e.g., 20 MW or greater) at two facilities: at Southern Company’s Plant Barry and at AEP’s Mountaineer Power Plant. A full scale, 110 MW project is currently being retrofitted at SaskPower’s Boundary Dam coal-fired EGU in Canada and is expected to begin operation in 2014. Another large scale retrofit project (240 MW) is in advanced stages of project development at NRG Energy’s WA Parish facility. There are also a number of smaller examples of CCS retrofits on coal-fired power plants.80

However, the EPA does not, at present, have sufficient information about costs to propose that partial CCS is the BSER for reconstructed utility boilers and IGCC units. Utility boilers are numerous and diverse in size and configuration, and the EPA does not have sufficient information about the range of specific configurations that would be necessary to estimate the cost of partial CCS, on either a source-specific basis or an

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industry-wide basis. In particular, retrofitting a plant with partial CCS would entail integrating the carbon capture equipment with the affected unit’s steam cycle (or with an external source of steam or heat) in order to release the captured CO₂ and regenerate the solvent or sorbent. The cost of a retrofit would depend on many site-specific details, including the space available for the capture equipment, and the EPA lacks information on such details for a significant portion of the industry.

Therefore, the EPA does not propose to find that partial CCS is the BSER for CO₂ emissions from reconstructed fossil fuel-fired utility boilers and IGCC units.

2. Conversion to or co-firing with natural gas

While conversion to or co-firing with natural gas in a utility boiler is a technically feasible option to reduce CO₂ emission rates, it is an inefficient way to generate electricity compared to use of an NGCC and the resultant CO₂ reductions are relatively expensive. The EPA found costs for natural gas co-firing to range from approximately $83/ton to $150/ton of CO₂ avoided.⁸¹ Even for cases where the natural gas could be co-fired without any capital investment or impact on the performance of the affected facility (e.g., an existing IGCC facility that

⁸¹ Chapter 2, GHG Abatement Measures TSD
already has a sufficient natural gas supply), the costs of CO₂ reduction would still be approximately $75/ton of CO₂ avoided. Therefore, we are not proposing natural gas co-firing as part of the BSER for modified or reconstructed steam generating units.

However, we specifically solicit comment on whether natural gas reburning (NGR) and/or similar technologies⁸² should be included as part of the BSER for reconstructed utility boilers and IGCC units. 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, the secondary (or reburn) fuel, natural gas, is injected to produce a slightly fuel rich reburn zone. Overfire air (OFA) is added above the reburn zone to complete burnout. As flue gas passes through the reburn zone, part of the nitrogen oxides (NOₓ) formed in the main combustion zone is reduced by hydrocarbon fragments (free radicals) and converted to molecular nitrogen (N₂). With NGR at 15 and 20 percent of the heat input to a coal-fired boiler, the CO₂ emission rate would be reduced by 4 percent.

⁸² Fuel lean gas reburning (FLGR™), also known as controlled gas injection, similar to NGR. In FLGR™, natural gas is injected above the main combustion zone at a lower temperature zone than in NGR and avoids creating a fuel-rich zone and maintains overall fuel-lean conditions. The FLGR™ technology is reported to achieve NOₓ control comparable to NGR using less than 10% natural gas heat input without the requirement for OFA. At a 10 percent heat input reburn rate, the CO₂ emission rate of a coal-fired EGU would be reduced by 4 percent.
reduced by 6 percent and 8 percent, respectively. In addition to reducing CO₂ emissions, a potential financial benefit of NGR compared to natural gas co-firing is the generation of additional NOₓ reductions. These reductions could reduce costs a source is currently paying for compliance with NOₓ requirements, including operations and maintenance costs associated with existing controls such as selective catalytic reduction systems and/or the cost of emission allowances under certain pollution control programs. **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, the secondary (or reburn) fuel, natural gas, is injected to produce a slightly fuel rich reburn zone. **Overfire air (OFA) is added above the reburn zone to complete burnout.** As flue gas passes through the reburn zone, part of the nitrogen oxides (NOₓ) formed in the main combustion zone is reduced by hydrocarbon fragments (free radicals) and converted to molecular nitrogen (N₂). With NGR at 15 and 20 percent of the heat input to a coal-fired boiler, the CO₂ emission rate would be reduced by 6 percent and 8 percent, respectively.

The EPA also takes comment on whether there are other factors or technologies related to co-firing that reduce its cost, and whether for these or other reasons, co-firing should
be considered as BSER for reconstructed fossil fuel-fired electric utility steam generating units.

3. Combined Heat and Power

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 greenhouse gas emissions. CHP has lower emission rates and can be more economic than separate electric and thermal generation. However, not all potentially modified and reconstructed utility boilers and IGCC units are located close enough to thermal hosts to economically or efficiently use the recovered thermal energy. Therefore, we are not proposing to find that CHP is the BSER for reconstructed utility boilers and IGCC units or stationary combustion turbines.

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 or without photovoltaic generation) with a fossil fuel-fired EGU. Both coal-fired and NGCC EGUs have demonstrated
the technical feasibility of integrating concentrating solar thermal energy for use in boiler feed water heating, preheating make up water, and/or producing steam for use in the steam turbine or to power the boiler feed pumps. While hybrid power plants can reduce the CO₂ emission rate by several percent compared to similar non-hybrid power plants, not all modified and reconstructed EGUs may have the space or meteorological conditions to generate enough solar thermal energy to successfully convert to a hybrid power plant. Solar thermal facilities require abundant sunshine and significant land area and the EPA does not have sufficient information about the range of specific configurations that would be necessary to estimate the cost of implementation, on either a source-specific basis or an industry-wide basis. We solicit comment on whether hybrid power plant technology is broadly applicable to modified and reconstructed EGUs and on the costs of integrating non-emitting generation.

Our understanding is that one of the benefits of hybrid fossil EGUs is decreased incremental cost of the non-emitting (e.g., solar thermal) generated electricity due to the ability to use equipment (e.g., HRSG, steam turbine, condenser, etc.) already included at the fossil fuel-fired EGU, as well as improvement of the electrical generation efficiency of the non-emitting generation. For example, solar thermal often produces
steam at relatively low temperatures and pressures and the conversion efficiency 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 HRSG) prior to expansion in the steam turbine, where it produces electricity. Upgrading the relatively low grade steam produced by the solar thermal facility improves the relative conversion efficiencies of the solar thermal to electricity process. The primary incremental costs of the non-emitting solar thermal 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 a comparable fossil only EGU to accommodate the additional steam load during sunny hours.

We specifically solicit comment on an alternate, but similar, approach for modified and reconstructed fossil fuel-fired EGUs to integrate lower emitting generation. The recovered thermal energy from natural gas-fired combustion turbines, fuel cells, or other combustion technology could be used to 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. However, at this time we do not have sufficient information on the costs or technical feasibility of this approach to include it as the BSER for reconstructed fossil fuel-fired utility boilers.

5. Reductions in Generation Associated with Dispatch Changes, Renewable Generation, and Demand Side Energy Efficiency

In the companion proposal in today’s Federal Register, which proposes emission guidelines for existing fossil fuel-fired EGUs, the EPA considered numerous measures that can and are being implemented to improve emission rates and to limit overall CO₂ emissions from fossil fuel-fired EGUs. The EPA grouped those measures into four main categories, or “building blocks.” The EPA proposed that each of the building blocks represents a method of CO₂ emission reduction at existing fossil fuel-fired EGUs that, when combined with the other building blocks, represent the “best system of emission reduction... adequately demonstrated” for existing fossil-fuel-fired EGUs under a 111(d) program. The building blocks are:

1. Lowering the carbon intensity of generation at individual affected EGUs (e.g., through heat rate improvements);
2. Reducing emissions of the most carbon-intensive affected EGUs to the extent that this can be accomplished cost-effectively by shifting generation to less carbon-intensive
existing NGCC units, including NGCC units that are under construction;

3. Reducing emissions of carbon-emitting EGUs to the extent that this can be accomplished cost-effectively by expanding the amount of new, lower (or no) carbon-intensity generation; and,

4. Reducing emissions of carbon-emitting EGUs to the extent that this can be accomplished cost-effectively by increasing demand-side energy efficiency.

In this rulemaking, we are, in effect, utilizing building block one – lowering the carbon intensity of generation at individual affected EGUs through heat rate improvements – as part of the BSER determination for modified units, but we are not proposing that building blocks two, three, or four are components of the BSER determination. We solicit comment on whether building blocks two, three and four would be appropriate in light of the fact that, unlike the CAA section 111(d) emission guidelines proposal, which will result in state plans that cover all existing sources, this proposal will result in a federal rule that covers only those sources that modify or reconstruct. We note that it is not possible in advance to determine which sources will do so. We solicit comment on any additional considerations that the EPA should take into
account in the applicability of building blocks two, three and four in the BSER determination.

6. Efficiency Improvements Achieved through the use of the most Efficient Generation Technology

We also considered whether the proposed emission limit for reconstructed fossil fuel-fired utility boilers and IGCC units should be based on the performance of the most efficient generation technology available, which we believe is a SCPC or supercritical CFB boiler for large sources, and subcritical for small sources. We propose to find that these technologies meet the criteria for the BSER.  

a. Technical Feasibility

The use of supercritical steam conditions has been demonstrated by many facilities since the 1960s for both large and small EGUs. In fact, the world’s first commercial supercritical pressure EGU was the 125 MW Philo Unit 6 that commenced operation in 1957. Currently commercially available materials capable of tolerating steam conditions of 30 megapascal (MPa) (4,350 pounds per square inch (psi)) and 605 °C (1,120 °F) have been demonstrated at coal-fired EGUs. In addition, even though the majority of recently constructed coal-

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83 Note that the discussion of efficiency improvements in this section is limited to reconstructed utility boilers and IGCC units. We discussed efficiency improvements for modifications below.
fired EGUs use a single steam reheat cycle, the use of a dual steam reheat cycle has been demonstrated by multiple facilities as technically feasible. For a facility to be considered reconstructed for NSPS purposes, the boiler itself would have to be substantially refurbished. As part of a reconstruction, an owner/operator would be able to replace the steam tubing and other necessary equipment to allow the use of the best demonstrated steam cycle. Therefore, this option is technically feasible.

It should be noted that this approach identifies as the BSER changes in production technology that would result in fewer emissions, and not add-on technology that would control emissions. The kraft pulp mill NSPS (40 CFR 60, subpart BB) is an example in which different equipment design (rather than add-on control) is the BSER for a modification or reconstruction.

b. CO₂ Reductions

The U.S. Department of Energy National Energy Technology Laboratory (DOE/NETL) has estimated that a new SCPC boiler using subbituminous coal would emit seven percent less CO₂ per MWh than a comparable subcritical boiler. Therefore, we estimate that this standard will result in reduction in emissions of at least seven percent when compared to the expected emissions of a reconstructed EGU using subcritical steam conditions. Smaller EGUs often use relatively low steam parameters and increasing

Comment [A37]: Isn’t this NETL estimate based on a comparison of the costs of new builds? EPA may want to provide further explanation of its consideration of any potential differences in cost for a reconstruction/retrofit in order to strengthen its basis for relying on this cost estimate.

EPA: In this case, we used the estimated emissions from a new supercritical boiler as compared to a new subcritical boiler to estimate differences in CO₂ emissions. We assume that the relationship between the two would be the same for newly constructed or reconstructed units.
the steam parameters to the maximum subcritical steam parameters reduces the CO₂ emissions rate. The average steam pressure and temperature for small EGUs that were reported to the information collection request associated with the Mercury and Air Toxics Standards rulemaking is 11 MPa (1,630 psig) and 527 °C (980 °F) and 40 percent have no steam reheat. Increasing the steam pressure to 20 MPa (2,900 psig) and 568 °C (1,054 °F) would reduce the CO₂ emission rate by 6 percent. In addition, the use of a single steam reheat cycle reduces the CO₂ emission rate by 10 percent compared to an equivalent EGU without a steam reheat cycle.

While the percent reduction in CO₂ emissions rate using efficiency improvements achieved through the use of the most efficient generation technology is less than could be achieved by a number of the other alternatives for the BSER that the EPA considered, as noted above, those other alternatives do not meet other criteria for the BSER. Efficiency improvements achieved through the use of the most efficient generation technology do achieve the greatest emission reductions of any of the remaining alternatives that the EPA is considering.

c. Costs, Structure of the Energy Sector

U.S. Department of Energy National Energy Technology Laboratory (DOE/NETL) has estimated, based on the levelized cost of electricity (LCOE), that the capital costs of a SCFC EGU are
approximately 3 percent more than a comparable subcritical EGU. In fact, the reduced fuel costs are significant enough that the overall cost to generate electricity is actually lower for a SCPC EGU compared to a subcritical EGU. Therefore, the emission reductions are considered cost effective for larger EGUs.

For smaller boilers, less than approximately 200 MW, it is the understanding of the EPA that manufacturers of steam turbines do not currently offer turbines that have been thermodynamically optimized to use supercritical steam conditions. Instead, for smaller applications, they would typically adapt their larger turbines for the application. The resulting designs have a higher cost premium than larger supercritical steam turbines and do not take full advantage of the potential efficiency improvements and the benefits of using a supercritical steam cycle are reduced. Therefore, for smaller reconstructed EGUs the EPA has determined that the BSER is the use of highest available subcritical steam conditions. The maximum viable subcritical steam parameters are 21 MPa (3,000 psi) and 570 °C (1,060 °F). The EPA specifically solicits comment on the efficiency benefits and the costs of using supercritical steam conditions for smaller EGU designs.

While we do not have data for the incremental costs of increasing steam parameters within subcritical conditions, modern materials are widely available that can tolerate the
maximum subcritical steam parameters. Therefore, we anticipate this cost is low. We solicit comment on these costs.

Designating the most efficient generation technology as the BSER for reconstructed fossil fuel-fired utility boilers and IGCC units will not have significant impacts on nationwide electricity prices. The reason is that the additional costs of the use of efficient generation will, on a nationwide basis, be small because few reconstructed coal-fired projects are expected and because at least some of these reconstructions can be expected to incorporate the most efficient generation technology even in the absence of a standard.

For the same reason, designation of the most efficient generation technology as the BSER for reconstructed fossil fuel-fired utility boilers and IGCC units will not have adverse effects on the structure of the power sector, will not impact fuel diversity, and will not have adverse effects on the supply of electricity.

d. Incentive for Technological Innovation

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 factor along with the other ones. When it comes to the selection of the BSER, the EPA recognizes that reconstructed sources face inherent constraints that newly
constructed greenfield sources do not; as a result, reconstructed sources present different, and in some ways more limited, opportunities for technological innovation or development. In this case, identifying the most efficient generation technology as the BSER promotes the further extension of that technology throughout the industry.

While some of the other options that the EPA considered in determining the BSER for reconstructed utility boilers and IGCC units would have led to greater opportunities for technology advancement, for the reasons discussed above, those other options did not meet other criteria. While the proposed standard is based on the use of the best available steam cycle, other energy efficiency measures will likely be developed and used (improved economizers, etc.) and these technologies will be transferrable to other EGUs.

7. Efficiency Improvements Achieved through a Combination of Best Operating Practices and Equipment Upgrades

The EPA also considered whether a combination of best operating practices and equipment upgrades would qualify as the BSER for a reconstruction. These measures are discussed in greater detail in Section VII. A reconstruction, because it occurs only when an owner/operator spends more than 50% of the cost of a replacement unit, generally entails fundamental decisions about what type of unit to rebuild. For example, one
reconstruction occurred following an explosion at the boiler and resulted in a rebuild of the entire unit including both the boiler and the accompanying steam turbine.

Because a reconstruction generally entails rebuilding the unit, operating practices and equipment upgrades are not applicable as BSER. Those entail smaller scale changes to the unit that may be expected to be rebuilt anyway. In addition, the emission reductions that could be achieved through best operating practices and equipment upgrades are smaller than the most efficient generation technology.

C. Determination of the Level of the Standard

Once the EPA has determined that a particular system or technology represents BSER, the EPA must establish an emission standard based on that system or technology. To determine an achievable emission standard we reviewed the emission rate information submitted by owners/operators of coal-fired EGUs to the EPA’s Clean Air Markets Division. For reconstructed fossil fuel-fired boiler and IGCC EGUs, the EPA proposes to find that the best available steam cycle - which qualify as the BSER - support a standard of 1,900 lb CO₂/MWh-net for large EGUs (i.e., those with heat input greater than 2,000 MMBtu/h), and 2,100 lb CO₂/MWh-net for small EGUs (i.e., those with a heat input 2,000 MMBtu/h or less). The U.S. Department of Energy National Energy Technology Laboratory (DOE/NETL) estimates that an IGCC unit
emission rate is comparable to those achieved by a supercritical coal-fired EGU. Therefore, for both technologies, these levels of the standard are based on the emission performance that can be achieved by a large pulverized or CFB coal unit using supercritical steam conditions and a small unit using subcritical steam conditions.

We are also soliciting comment on whether the emission limit may be more appropriately set at a different level. Based on the rationale included in the TSD, we are soliciting comment on a range of 1,700 to 2,100 lb CO₂/MWh-net for large units and 1,900 to 2,300 lb CO₂/MWh-net for small units. An emission rate of 1,700 lb CO₂/MWh-net could potentially be met by an EGU using advanced ultra-supercritical steam conditions.\textsuperscript{84}

We are not currently considering a standard more stringent than 1,700 lb CO₂/MWh-net for large units. Available information indicates that an EGU facility could not meet a standard of 1,600 lb CO₂/MWh-net based on the use of an advanced ultra-supercritical steam cycle, and instead would be required to implement partial CCS, co-fire approximately 40 percent natural gas directly in the boiler, or integrate non emitting or lower emitting technology in the facility's design (i.e., a hybrid power plant). We are not currently considering a standard more

\textsuperscript{84} Advanced ultra-supercritical steam conditions are 700 – 760 °C (1,290 – 1,400 °F) and 36 MPa (5,000 psi)
more stringent than 1,900 lb CO₂/MWh-net for small units because available information indicates that a small EGU facility could only meet a standard of 1,800 lb CO₂/MWh-net burning bituminous coal and using the best available subcritical steam cycle. Modified facilities burning other coal types would be required to implement partial CCS, co-fire approximately 10 percent natural gas directly in the boiler, or integrate non-emitting or lower emitting technology in the facility's design (i.e., a hybrid power plant).

We are not currently considering a standard less stringent than 2,100 lb CO₂/MWh-net for large units because at that level, the NSPS would not necessarily promote the use of the best available steam cycle. At an emissions rate of 2,200 lb CO₂/MWh, large EGUs would not be required to use efficient generation technologies (e.g., they could use subcritical steam conditions). We are not currently considering a standard less stringent than 2,300 lb CO₂/MWh-net for small units because at that level, the NSPS would not necessarily promote the use of the best available steam conditions because many smaller subcritical units are operating well below 2,300 lb CO₂/MWh-net.

D. Compliance Period

The EPA is proposing that sources would be required to meet the proposed standards on a 12 operating-month rolling basis. The proposed compliance period requirements and rationale are
the same as in the January 2014 proposal. This section provides a summary of the rationale. For additional detail, see 79 FR at 1,481-2 and 1,482-4.

The 12-operating-month averaging period being proposed is important because of the inherent variability in power plant GHG emissions rates. Establishing a shorter averaging period would necessitate establishing a standard to account for the conditions that result in the lowest efficiency and therefore the highest GHG emissions rate.

EGU efficiency has a significant impact on the source’s GHG emission rate. EGU efficiency can vary from month to month throughout the year. For example, high ambient temperature can negatively impact the efficiency of combustion turbine engines and steam generating units. As a result, an averaging period shorter than 12 operating-months would require us to set a standard that could be achieved under these conditions. This standard could potentially be high enough that it would not be a meaningful constraint during other parts of the year. In addition, operation at low load conditions can also negatively impact efficiency. It is likely that for some short period of time an EGU will operate at an unusually low load. A short averaging period that accounts for this operation would again not produce a meaningful constraint for typical loads.
On the other hand, a 12-operating-month rolling average explicitly accounts for variable operating conditions, allows for a more protective standard and decreased compliance burden, allows EGUs to have and use a consistent basis for calculating compliance (i.e., ensuring that 12 operating months of data would be used to calculate compliance irrespective of the number of long-term outages), and simplifies compliance for state permitting authorities. The EPA proposes that it is not necessary to have a shorter averaging period for CO₂ from these sources because the effect of GHGs on climate change depends on global atmospheric concentrations which are dependent on cumulative total emissions over time, rather than hourly or daily emissions fluctuations or local pollutant concentrations. Unlike for emissions of criteria and hazardous air pollutants, we do not believe that there are measurable implications to health or environmental impacts from short-term higher CO₂ emission rates as long as the 12-month average emissions rate is maintained.

VII. Rationale for Emission Standards for Modified Fossil Fuel-fired Utility Boilers and IGCC Units

A. Introduction

In this section we explain our rationale for proposing, as the “best system of emission reduction ... adequately demonstrated” for modified fossil fuel-fired utility boiler and
IGCC EGUs, a combination of best operating practices and equipment upgrades.

We include in this discussion (1) our rationale for rejecting other alternatives as BSER, (2) a description of efficiency improvements achieved through a combination of best operating practices and equipment upgrades and our rationale for selecting it as BSER and (3) our rationale for co-proposed alternative standards of performance based on this BSER (including varying the standard depending upon whether the affected source would be subject to a CAA section 111(d) state plan (or promulgated federal plan) for CO₂.

B. Identification of the Best System of Emission Reduction for Modified Fossil Fuel-fired Utility Boilers and IGCC Units

1. Options considered

For the same reasons explained above for reconstructed fossil fuel-fired boiler and IGCC EGUs, the EPA is not proposing the following options to be BSER for modified fossil fuel-fired utility boiler and IGCC units: (1) the use of partial carbon capture and storage (CCS), (2) conversion to (or co-firing with) natural gas, (3) the use of combined heat and power (CHP), (4) Hybrid Power Plants, and (5) reductions in generation associated with dispatch changes, renewable generation, and demand side energy efficiency.
In this section, we evaluate two other options for BSER: (1) efficiency improvements achieved through the use of the most efficient generation technology, and (2) efficiency improvements achieved through a combination of best operating practices and equipment upgrades.

2. Use of the most efficient generation technology

We considered whether the BSER for modified fossil fuel-fired utility boilers and IGCC units should be based on the performance of the most efficient generation technology available, which we believe is a supercritical\(^{85}\) unit (i.e., a supercritical pulverized coal (SCPC) or supercritical circulating fluidized bed (CFB) boiler) for large sources, and a subcritical unit for small sources. However, as was previously noted, the existing fleet of fossil fuel-fired steam-generating boilers is numerous and diverse in size and configuration (including steam parameters), and the EPA does not have sufficient information about the range of configurations that would be necessary to estimate the cost of upgrading the steam cycle (switching to higher grade of materials in the furnace, subcritical coal-fired boilers are designed and operated with a steam cycle below the critical point of water. Supercritical coal-fired boilers are designed and operated with a steam cycle above the critical point of water. Increasing the steam pressure and temperature improves the efficiency of a steam turbine converting thermal energy to electricity, which in turn leads to increased efficiency and a lower emission rate.)
replacement of the steam drum and conversion to a once through design, etc.) and auxiliary equipment to the most efficient generating technology. For a given boiler design, steam pressures and temperatures are limited by the properties of the materials (boiler tubes, etc.) and cannot be increased without replacing those components. We do not have sufficient information on the number of components that would need to be replaced or on the costs of replacing individual components. Furthermore, we recognize that, in at least some cases, requiring a unit to meet levels achievable by a supercritical unit, when it was not originally designed to do so, could require significant modifications to both the boiler and turbine that could start to approach the replacement cost for the unit.

Unlike in the case of reconstruction explained above, it is the understanding of the EPA that modifications do not typically involve the type of boiler rebuilding that would make this an option with reasonable cost. Consequently, the EPA does not propose to find that the use of the most efficient generation technology meets the criteria for the BSER for a uniform nationwide standard of performance.

3. Best Operating Practices and Equipment Upgrades

The second option that EPA considered for modified fossil fuel-fired utility boilers and IGCC units is a combination of best operating practices and equipment upgrades. Best operating
practices includes both operating the unit in the most efficient manner for a given operating condition and replacing worn components in a timely manner. Equipment upgrades involve replacing existing components with upgraded ones or a more extensive overhaul of major equipment (turbine or boiler). We propose to find that this option meets the criteria for BSER for these EGUs.

In addition, we are co-proposing two alternative standards of performance reflective of this BSER. In the first co-proposed alternative, all modified utility boilers and IGCC units will be required to meet a unit-specific emission standard. In the second co-proposed alternative, modified sources will be required to meet unit-specific emission limits that will depend on whether the affected unit undertakes the modification before it becomes subject to a section 111(d) state plan (or promulgated federal plan), or after it becomes subject to such a plan. Each variation of the BSER meets the criteria, which we discuss next. We describe the variations in more detail in the section concerning the standards of performance, which follows the discussion of the criteria.

a. Technical Feasibility

A wide range of studies have been performed evaluating the
opportunity to improve the heat rate (or efficiency)\(^{86}\) of an existing power plant without upgrading to the most efficient generation technology available. These studies are summarized in Chapter 2 of the TSD, “GHG Abatement Measures”\(^{87}\) which explains that, while the studies are different in the level of detail and assumptions, the results of the studies overall suggest that the U.S. coal-fired EGU existing fleet is theoretically capable of achieving heat rate improvements ranging from 9 to 15 percent.

Many of the detailed engineering studies describe a wide range of opportunities to improve heat rate including improvements to the: (1) materials handling equipment at the plant, (2) economizer, (3) boiler control systems, (4) soot blowers, (5) air heaters, (6) steam turbine, (7) feedwater heaters, (8) condenser, (9) boiler feed pumps, (10) induced draft (ID) fans, (11) emission controls, and (12) water treatment systems.

As the studies show, these types of upgrades have been made

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\(^{86}\) The heat rate is a common way to measure EGU efficiency. As the efficiency of a fossil fuel-fired EGU is increased, less fuel is burned per kilowatt-hour (kWh) generated by the EGU. This results in a corresponding decrease in CO\(_2\) and other air pollutant emissions. Heat rate is expressed as the number of British thermal units (Btu) or kilojoules (kJ) that are required to generate one kilowatt-hour (kWh) of electricity. Lower heat rates are associated with more efficient fossil fuel-fired EGUs.

at a wide range of power plants, demonstrating their technical feasibility.

b. CO₂ Reductions

This approach would achieve reasonable reductions in CO₂ 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.

c. Costs

The EPA reviewed the engineering studies available in the literature and selected the Sargent & Lundy 2009 study as the basis for its assessment of heat rate improvement potentials from equipment and system upgrades. We focused on thirteen heat rate improvement methods discussed by Sargent & Lundy and listed in Table 2-13 of the “GHG Abatement Measures” TSD. We used the average of the estimated costs (in $/kW) for each method to develop the cost-ranked list of heat rate improvement methods (listed by costs from lowest to highest in the table). The first nine items in Table 2-13 contribute about 15 percent of the total average $/kW cost for all items. We believe it is

Comment [A38]: Please make sure this section is consistent with the discussion in the 111(b) preamble and incorporates any changes resulting from the interagency process.

EPA: Agreed, prior to signature we will ensure that the relevant sections are consistent between the two preambles.

reasonable to consider those nine no-cost and low-cost heat rate improvement methods as belonging in the category of what has been described above as best practices. The remaining four methods are higher cost heat rate improvement opportunities that we believe properly fall into the category discussed here as equipment or system upgrades. Using an average of the ranges of potential Btu improvements estimated by Sargent & Lundy for the four upgrade methods, equipment or system upgrades could provide a 4 percent heat rate improvement if all were applied on an EGU that has not already made those upgrades.

The 2009 Sargent & Lundy study included an estimated range of heat rate improvement, and the associated range of capital cost for each heat rate improvement method, for units ranging in size from 200 MW to 900 MW. If the methods and unit sizes are combined, as though they were all applied on a single EGU, the range of Sargent & Lundy estimated Btu reductions (412 to 1205 Btu) resulted in associated combined capital costs in the range of $40-150/kW. The wide ranges of estimated Btu reductions and capital costs are indicative of the wide range of real differences in the many details of site specific EGU designs, fuel types, age, size, ambient conditions, current physical condition, etc. The EPA’s analysis, therefore, assumed $100/kW as a representative combined heat rate improvement capital cost to achieve whatever Btu reduction is possible at an average
site.

The EPA heat rate improvement analysis resulted in the following summary conclusions:

- Some degree of heat rate improvement is already economic for high heat rate – high coal cost EGUs.
- If a fleet-wide average 6 percent heat rate is technically feasible, it would also be economic on the basis of fuel savings alone, before consideration of the value of the associated CO₂ emission reductions, on a fleet-wide basis at today’s coal prices if the associated average capital cost is about $75/kW or less.
- Even at a capital cost of $100/kW and an IPM projected 2020 coal price of $2.62/MMBtu, the fleet-wide cost of CO₂ reduction via 6 percent heat rate improvement would be a relatively low $7.7/tonne of CO₂ avoided.

Based on this assessment, the EPA determines that the unit-specific emission limit based on historical best performance (which captures the good operating practice at the unit) coupled with an additional two percent reduction (which captures minimum opportunities for additional heat rate improvements from equipment and system upgrades) can be achieved at reasonable cost.

The EPA’s modeling tools do not allow projection of any

Comment [A39]: In describing the basis for requiring 2% efficiency improvement beyond a unit’s best historical performance, EPA may want to provide additional information about why 2% is a technically achievable improvement at a unit level and not just at a fleet-wide level. For example, what if a facility recently completed efficiency upgrades that are already included in their best historical performance?

EPA Response: We are proposing that the emission standard for reconstructed facilities be no lower than the proposed standard for reconstructed facilities to account for facilities that have already undertaken efficiency upgrades.
specific number of utility boilers and IGCC units that are expected to trigger the NSPS modification provision. As discussed below, however, the EPA believes there are likely to be few, if any. Hence, in this case, a unit-specific standard of performance will not have significant impacts on nationwide electricity prices or on the structure of the nation’s energy sector.

d. Incentive for Technological Development

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 weigh this factor, along with the various other factors. With the selection of emissions controls, modified sources face inherent constraints that newly constructed greenfield and even 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 proposed standards promote technological development by promoting further development and market penetration of equipment upgrades and process changes that improve plant efficiency.

C. Determination of the Level of the Standard
Once the EPA has determined that a particular system or technology represents BSER, the EPA must establish an emission standard based on that technology.

Because the existing fossil fuel-fired steam-generating boilers are numerous and diverse in size and configuration – and because the EPA has no way to predict which of those sources may modify - developing a single standard for all modified utility boilers or IGCC units is challenging. The EPA considered a sub-categorization approach, but, as is detailed in Chapter 2 of the TSD, “GHG Abatement Measures”, analysis of available data did not support a number of potential sub-categorization options - such as unit size, type or age - that intuitively seemed logical.

In this action, the EPA is co-proposing two alternative standards of performance for modified utility boilers and IGCC units. In the first co-proposed alternative, all modified sources would meet a unit-specific emission limit. In the second co-proposed alternative, the modified source would be required to meet a unit-specific emission limit that will depend on the timing of the modification.

For utility boilers or IGCC units undertaking modifications, the EPA is proposing that the BSER has two components: (1) that the source operates consistently with its own best demonstrated historical performance; and (2) that the
source implements other available heat rate improvement measures including upgrading of some components of the unit. Specifically, for the first co-proposed alternative, a modified utility boiler or IGCC unit would be required to maintain an emission rate that equals the unit’s best demonstrated annual performance during the years from 2002 to the year the modification occurs, multiplied by 98 percent (i.e., a two percent further reduction), but not to be more stringent than the emission limit that would be applicable to the source if it were a reconstructed source. Consistent with the heat rate improvement analysis in the 111(d) proposal, we selected 2002 to assure we captured the impacts of maintenance cycles and year to year natural variability in CO₂ emission rate performance to capture the best historical performance. We solicit comment on whether we should select a year prior to or subsequent to 2002 for purposes of determining the best historical emission rate.

As mentioned, the EPA is also co-proposing standards of performance that are dependent on the timing of the modification. Specifically, a source that modifies prior to becoming subject to a CAA 111(d) plan would be required to meet an emission limit that is determined using the same methodology described in the first co-proposed alternative. The modified utility boiler or IGCC unit would be required to maintain an emission rate that equals the unit’s best demonstrated annual
performance during the years from 2002 to the year the modification occurs, multiplied by 98 percent (i.e., a two percent further reduction based on equipment upgrades), but not to be more stringent than the emission limit applicable to a corresponding reconstructed source. The EPA is proposing that units undertaking modifications after they become subject to a CAA section 111(d) plan would be required to meet a unit-specific emission limit that is determined by the 111(d) permitting implementing authority from an assessment to identify energy efficiency improvement opportunities for the affected source. This standard is informed by the fact that, as we discuss in the Legal Memorandum, these sources would remain subject to the requirements of the CAA section 111(d) plan even after modifying.

The EPA also solicits comment on whether the period of best historical performance should be the years from 2002 to the time when the unit becomes subject to the CAA 111(d) plan, rather than to the time of the modification.

We are considering different standards applicable before and after a source becomes subject to a state 111(d) plan because we are concerned that, as a result of implementation of state plans, the additional two percent efficiency improvement

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89 Add cite Legal Memorandum available in rulemaking docket ID: EPA-HQ-OAR-20913-0602.
(based on efficiency improvements) may be unachievable for a substantial number of sources that make efficiency improvements as part of a state 111(d) plan. Specifically, we are concerned that where a state imposes efficiency improvements on a source, or where a source undertakes efficiency improvements to comply with the state plan, it will have already attained the maximum level of efficiency improvement that is achievable for that unit. As a result, the source would be unable to undertake additional improvements to meet the highest level of efficiency plus the additional two percent reduction (based on equipment upgrades) that we are considering. We recognize that in some states, 111(d) plans may require no or limited efficiency improvements on a specific unit. In such cases, we expect such a unit to be able to achieve the standard we are considering for sources that modify prior to becoming subject to a state 111(d) plan. Accordingly, for such sources, we anticipate that the audit process that we are considering will result in an emission rate consistent with the highest level of efficiency plus two percent (based on equipment upgrades) that we are considering for sources that modify prior to becoming subject to a state plan.

For this co-proposal, the EPA is proposing that the date for determining whether a unit is subject to a CAA section 111(d) plan is the date that the plan is initially submitted to
the EPA. Although a state’s plan is still subject to the EPA’s approval, we believe this represents a reasonable point to determine that a source is subject to a 111(d) plan, because at that point the operator would know what requirements the source would have to meet, and would have confirmation of the state’s intention to submit that plan to meet the requirements of 111(d). We are also taking comment on a range of other dates including: June 30, 2016 (the original state plan submission deadline), the date that the state promulgates its rule, the date the EPA approves the rule, and January 1, 2020 (the proposed initial compliance date for state plans).

For a source modifying after a CAA section 111(d) plan becomes applicable, a unit-specific emission standard will be determined by the 111(d) implementing authority from the results of an energy efficiency audit to identify technically feasible heat rate improvement opportunities at the affected source.

An energy efficiency audit, or assessment, is an in-depth energy study identifying all energy conservation measures appropriate for a facility given its operating parameters. An energy audit is a process that involves a thorough examination of potential savings from energy efficiency improvements, pollution prevention, and productivity improvement. It leads to the reduction of emissions of pollutants through process changes and other efficiency
modifications. Besides reducing operating and maintenance costs, improving energy efficiency results in decreased fuel use which results in a corresponding decrease in emissions. Such an energy assessment requirement is included in the National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters (40 CFR part 63, subpart DDDDD).

We propose that the energy assessment would include, at a minimum, the following elements:

1. A visual inspection of the facility to identify steam leaks or other sources of reduced efficiency;
2. A review of available engineering plans and facility operation and maintenance procedures and logs; and
3. A comprehensive report detailing the ways to improve efficiency, the cost of specific improvements, benefits, and the time frame for recouping those investments.

We propose that the energy assessment be conducted by energy professionals or engineers that have expertise in evaluating energy systems. We specifically request comment on: (1) whether energy assessor certification should be required; (2) if certification were required, what should the basis of the certification be; and (3) whether there are organizations that provide certification of specialists in evaluating energy systems. We propose that the 111(d) implementing authority will
determine a unit-specific emission limit based on the results of the energy efficiency audit and we also request comment on: (1) whether the rule should require implementation of identified energy efficiency improvements; and (2) if implementation were required, what the determining factor(s) for requiring the whether the required improvements should be identified as reasonable. Finally, we request comment on: (1) whether an energy efficiency audit recently completed (e.g., within 3 years of the modification) that meets or is amended to meet the rule’s energy audit requirements can be used to satisfy the energy efficiency audit requirement and, in such instances, whether energy assessor approval and qualification requirements should be waived; and (2) whether facilities that operate under an energy management program compatible to ISO 50001\(^9\) that includes the affected units can be used to satisfy the energy efficiency audit requirement.

The EPA also seeks comment on whether, and under what circumstances, the energy audit methodology – i.e., determining the emission limit from the results of the energy audit – should

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\(^9\) ISO 50001 is a specification created by the International Organization for Standardization (ISO) for an energy management system. The standard specifies the requirements for establishing, implementing, maintaining and improving an energy management system, whose purpose is to enable an organization to follow a systematic approach in achieving continual improvement of energy performance, including energy efficiency, energy security, energy use and consumption.
be an option for sources that modify before becoming subject to 
a CAA section 111(d) plan. In particular, the EPA seeks comment 
on whether the audit methodology should be an option for all 
units that modify, prior to becoming subject to a CAA section 
111(d) plan, or if it should be an option for sources that 
provide evidence that significant energy efficiency improvements 
were implemented after 2002 but before the modification.

D. Compliance Period

The EPA is proposing that sources would be required to meet 
the proposed standards on a 12 operating-month rolling basis. 
The compliance period requirements and rationale being proposed 
for modified boilers and IGCC units are the same as the 
requirements and rationale being proposed for reconstructed 
utility boilers and IGCC units (see section VII.D. of this 
preamble), as well as the compliance period requirements and 
rationale in the January 2014 proposal. For additional detail, 
see 79 FR at 1,481/2 and 1,482/1 and the TSB.

VIII. Rationale for Emission Standards for Reconstructed Natural 
Gas-fired Stationary Combustion Turbines

A. Identification of the Best System of Emission Reduction

The EPA evaluated three different control technology 
configurations as potentially representing the “best system of 
emissions reductions … adequately demonstrated” for 
reconstructed natural gas-fired stationary combustion turbines:
(1) NGCC technology with CCS, (2) NGCC technology by itself, and (3) high efficiency simple cycle aeroderivative turbines.

1. NGCC technology with CCS

We are not proposing to find that CCS technology is the BSER for reconstructed natural gas-fired stationary combustion turbines for the same reasons why we are not proposing to find that CCS technology is the BSER for steam-generating units: An owner/operator of an existing source that is undertaking reconstruction has challenges not faced when building a new NGCC unit because the existing unit may be located at a site with space constraints that would make installation of CCS problematic. We do not have sufficient information about the universe of existing sources to be able to determine the costs of CCS, in light of these space constraints.

2. NGCC technology

For the reasons explained below, we find NGCC technology to be BSER for reconstructed natural gas-fired stationary combustion turbines.

a. Technical Feasibility

NGCC technology is widely used in the power sector today. There are hundreds of NGCCs in the U.S. and in other countries.

b. Emission Reductions

NGCC technology is the most efficient technology for natural-gas fired stationary combustion turbines. It has an
emission rate that is approximately 25 percent lower than the most effective main alternative technology, which is the simple cycle combustion turbine.

c. Cost

NGCC technology is one of the lowest cost forms of baseload and intermediate load electricity generation. Even in the case of a simple cycle turbines that operates at a capacity factor of greater than one-third, the cost of replacement with a NGCC unit is likely to be cost effective based on consideration of fuel savings alone. In the new source proposal (79 FR 1459), we explained that at capacity factors of greater than 20 percent, the LCOE of a combined cycle unit would be less than the LCOE of a simple cycle turbine. Because the cost of adding a HRSG to a simple cycle turbine is less than the cost of building a full combined cycle unit, the same holds true with a comparison of replacing a simple cycle turbine and upgrading it to a combined cycle turbine. Furthermore, if the owner/operator of a simple cycle turbine wishes to make a modification, they could do so - without having to comply with the requirements of this proposal - by maintaining an average annual capacity factor of less than one-third. As we explained in the proposal, few simple cycle turbines operate at an annual capacity factor of greater than one-third. (79 FR 1459)

d. Incentive for technology innovation
We recognize that because NGCC technology is already the state of the art technology, and is widely used, for natural gas stationary combustion turbines, identifying this technology as the BSER may not provide significant incentive for technology innovation. However, we are according less weight to this factor in this case because we consider this technology to be highly efficient and because the only more stringent alternative – CCS – is one that we are not proposing to identify as BSER, for reasons discussed above.

3. High efficiency simple cycle aeroderivative turbines

The use of high efficiency simple cycle aeroderivative turbines does not provide emission reductions when compared to the NGCC technology. According to the Annual Energy Outlook (AEO) 2013 emissions rate information, advanced simple cycle combustion turbines have a base load rating CO₂ emissions rate of 1,150 lb CO₂/MWh-gross, which is higher than the base load rating emission rates of 830 and 760 lb CO₂/MWh-gross for the conventional and advanced NGCC model facilities, respectively. In addition, simple cycle technology is more expensive than NGCC technology; and it does not further develop or promote use of the most advanced emission control technology. For these reasons, we do not find it to be the BSER for reconstructed natural gas-fired stationary combustion turbines.

B. Determination of the Standards of Performance
The proposed standards of performance for reconstructed natural gas-fired stationary combustion turbines, which are based on BSER being efficient NGCC technology, are consistent with those that were proposed for new natural gas-fired stationary combustion turbine sources, as described in the January 8, 2014 proposal (79 FR 1430). In that proposal, the EPA indicated that it had reviewed the CO₂ emissions data from 2007 to 2011 for natural gas-fired (non-CHP) combined cycle units that commenced operation on or after January 1, 2000, and that reported complete electric generation data, including output from the steam turbine, to the EPA. A more detailed description of the emissions data analysis is included in a TSD in the docket for that rulemaking⁹¹ and is also included in the docket for this proposal.

Consistent with the January 8, 2014 proposal, the EPA proposes to subcategorize the turbines into the same two size-related subcategories currently in subpart KKKK for standards of performance for the combustion turbine criteria pollutants. These subcategories are based on whether the design heat input rate to the turbine engine is either 850 MMBtu/h or less, or greater than 850 MMBtu/h. We further propose to establish different standards of performance for these two subcategories.

This subcategorization has a basis in differences in several types of equipment used in the differently sized units, which affect the efficiency of the units. Because of these differences in equipment and inherent efficiencies of scale, the smaller capacity NGCC units (850 MMBtu/h and smaller) are less efficient than the larger units (larger than 850 MMBtu/h).

We are proposing standards of performance of 1,000 lb CO₂/MWh-gross for the large units and 1,100 lb CO₂/MWh-gross for the small units; and we are requesting comment on a range of 950 to 1,100 lb CO₂/MWh-gross for the large turbine subcategory and 1,000 to 1,200 lb CO₂/MWh-gross for the small turbine subcategory.

IX. Rationale for Emission Standards for Modified Natural Gas-fired Stationary Combustion Turbines

A. Identification of the Best System of Emission Reduction

We believe that the analysis above with regards to reconstructed natural gas-fired stationary combustion turbines is also applicable to modified natural gas-fired stationary combustion turbines. The only potential difference that the EPA has identified is consideration of cost because the actions that could trigger modification are less extensive changes at the

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facility. We have considered four different scenarios that could trigger the modification provisions: (1) modification of an older (e.g., pre 2000) combined cycle unit, (2) modification of a newer (e.g., a built in 2000 or later) combined cycle unit, (3) upgrading of a simple cycle turbine to a combined cycle unit, and, (4) modification to a simple cycle turbine other than upgrading to a combined cycle unit. As described below, in each of these cases, we believe that NGCC is cost-effective.

1. Modifications to an older (e.g., pre-2000) combined cycle unit

Because the performance of combined cycle technology has improved so significantly since 2000, we believe that upgrading to current technology is likely to be cost effective when one considers a combination of fuel savings, and performance benefits (the ability to start up the unit more quickly and operate more efficiently over a wider range of loads).

2. Modifications to a newer combined cycle unit

These modifications are likely to be made to return the unit to close to its original operating performance, and would be consistent with the requirements of today’s proposal, and are not likely to significantly increase the cost of the project.

3. Upgrading a simple cycle turbine to a combined cycle unit

These modifications would be made to upgrade the efficiency of the unit, and are consistent with the requirements of today’s
proposal, and are not likely to significantly increase the cost of the project.

4. Modifications to a simple cycle turbine other than upgrading to combined cycle

As was noted above and in the new source proposal - when operating at higher capacity factors, the use of combined cycle technology instead of simple cycle technology pays for itself in fuel savings alone.

For these reasons, we find the use of NGCC technology to be BSER for modified natural gas-fired combustion turbines.

B. Determination of the Standards of Performance for Modified Natural Gas-fired Stationary Combustion Turbines

We propose that the same standards of performance described above for reconstructed natural gas-fired stationary combustion turbines are also appropriate for modified natural gas-fired stationary combustion turbines.

We are requesting comment on a range of 950 to 1,100 lb CO₂/MWh-gross (430 to 500 kg CO₂/MWh) for the large turbine subcategory and 1,000 to 1,200 lb CO₂/MWh-gross (450 to 540 kg CO₂/MWh) for the small turbine subcategory.

For sources that are subject to a CAA section 111(d) plan, the EPA is also soliciting comment on whether the sources should be allowed to elect, as an alternative to the otherwise applicable numeric standard, to meet a unit-specific emission
standard, determined by the 111(d) permitting implementing authority, based on implementation of identified energy efficiency improvement opportunities applicable to the source.

X. Impacts of the Proposed Action

As explained in the RIA for this proposed rule, the EPA expects few, if any, sources will trigger either the NSPS modification or reconstruction provisions that we are proposing today. Because the EPA is aware of a limited number of units that have notified the EPA of NSPS modifications in the past, we have conducted an illustrative analysis of the costs and benefits for a representative unit. Based on the analysis, which is presented in Chapter 9 of the RIA, the EPA expects that this proposed rule will result in potential CO₂ emission changes, quantified benefits, and costs for a unit that was subject to the modification provision. In this illustrative example based on a hypothetical 500 MW coal-fired unit, we estimate costs, net of fuel savings, of $0.78 million to $4.5 million (2011$) and CO₂ reductions of 133,000 to 266,000 tons in 2025. The combined climate benefits from reductions in CO₂ and health co-benefits from reductions in SO₂, NOₓ, and PM₂.₅ total $18 to $33 million (2011$) at a 3 percent discount rate for emission reductions in

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Note that the EPA does not project any difference in the impacts between the alternative to regulate sources under subparts Da and KKKK versus regulating them under new subpart TTTT
2025 for the lowest emission reductions scenario and $35 to $65 million (2011$) at a 3 percent discount rate for emission reductions in 2025 for the highest emission reduction scenario.  

A. What are the air impacts?

As explained immediately above, the EPA expects few, if any, modified or reconstructed EGUs in the period of analysis. Because there have been a limited number of units that have notified the EPA of NSPS modifications in the past, we have conducted an illustrative analysis of the impacts for a hypothetical unit that triggered the modification provision. For this illustrative example, we estimate CO₂ reductions of 133,000 to 266,000 tons in 2025. Additionally, we estimate co-reductions of SO₂, NOₓ, and PM₂.₅.

B. What are the energy impacts?

This proposed rule is not anticipated to have significant impacts on the supply, distribution, or use of energy. As previously stated, the EPA expects few, if any, reconstructed or modified EGUs in the period of analysis and the nationwide cost impacts to be minimal as a result.

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94 For purposes of this summary, we present climate benefits from CO₂ that were estimated using the model average social cost of carbon (SCC) at a 3% discount rate. We emphasize the importance and value of considering the full range of SCC values, however, which include the model average at 2.5% and 5%, and the 95th percentile at 3%. Similarly, we summarize the health co-benefits in this synopsis at a 3% discount rate. We provide estimates based on additional discount rates in the RIA.
C. What are the compliance costs?

The EPA believes this proposed rule will have minimal compliance costs associated with it, because, as previously stated, the EPA expects, few, if any, modified or reconstructed EGUs in the period of analysis. Because the EPA is aware of a limited number of units that have notified the EPA of NSPS modifications in the past, we have conducted an illustrative analysis of the costs and benefits for a representative unit. Based on the analysis, which is presented in Chapter 9 of the RIA, the EPA estimates compliance costs, net of fuel savings, of $0.78 to $4.5 million (2011$) in 2025 for a hypothetical unit that triggered the modification provisions.

D. How will this proposal contribute to climate change protection?

As previously explained, the special characteristics of GHG make it important to take action to control the largest emissions categories without delay. Unlike most traditional air pollutants, GHG persist in the atmosphere for time periods ranging from decades to millennia, depending on the gas. Fossil fuel-fired power plants emit more GHG emissions than any other stationary source category in the U.S.

This proposed rule would limit GHG emissions from modified fossil fuel-fired electric utility steam generating units (utility boilers and IGCC units) to levels consistent with the
unit’s best potential performance. GHG emissions from reconstructed utility boilers and IGCC units would be limited to levels consistent with modern, efficient generating technology (e.g., supercritical steam cycles). While the EPA expects few, if any, units to trigger the modification or reconstruction provisions, this proposed rule would limit GHG emissions from any modified and reconstructed stationary combustion turbines to levels consistent with modern, efficient natural gas combined cycle technology. As a result, this proposed rule will contribute to the actions required to slow or reverse the accumulation of GHG concentrations in the atmosphere, which is necessary to protect against projected climate change impacts and risks.

E. What are the economic and employment impacts?

As previously stated, the EPA anticipates few, if any, units will trigger the proposed modification or reconstruction provisions. For this reason, the proposed standards will result in minimal emission reductions, costs, or quantified benefits by 2025. There are no macroeconomic or employment impacts expected as a result of these proposed standards. As previously stated, the EPA anticipates few, if any, units will trigger the proposed modification or reconstruction provisions. Because there have been a limited number of units that have notified the EPA of NSPS modifications in the past, we have conducted an
illustrative analysis of the costs and benefits for a representative unit. Based on the analysis, which is presented in Chapter 9 of the RIA, the combined climate benefits from reductions in CO₂ and health co-benefits from reductions in SO₂, NOₓ, and PM₂.₅ total $18 to $33 million (2011$) at a 3 percent discount rate for emission reductions in 2025 for the lowest emission reductions scenario and $35 to $65 million (2011$) at a 3 percent discount rate for emission reductions in 2025 for the highest emission reduction scenario.**

F. What are the benefits of the proposed standards?

As previously stated, the EPA anticipates few, if any, units will trigger the proposed modification or reconstruction provisions. Because there have been a limited number of units that have notified the EPA of NSPS modifications in the past, we have conducted an illustrative analysis of the costs and benefits for a representative unit. Based on the analysis, which is presented in Chapter 9 of the RIA, the combined climate benefits from reductions in CO₂ and health co-benefits from reductions in SO₂, NOₓ, and PM₂.₅ total $18 to $33 million (2011$).

**For purposes of this summary, we present climate benefits from CO₂ that were estimated using the model average social cost of carbon (SCC) at a 3% discount rate. We emphasize the importance and value of considering the full range of SCC values, however, which include the model average at 2.5% and 5%, and the 95th percentile at 3%. Similarly, we summarize the health co-benefits in this synopsis at a 3% discount rate. We provide estimates based on additional discount rates in the RIA.
at a 3 percent discount rate for emission reductions in 2025 for the lowest emission reductions scenario and $35 to $65 million (2011$) at a 3 percent discount rate for emission reductions in 2025 for the highest emission reduction scenario. As previously stated, the EPA anticipates minimal CO₂-emission changes resulting from the rule in the period of analysis. Therefore, there are no direct monetized climate or human health benefits associated with this rulemaking.

XI. Statutory and Executive Order Reviews

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

Under Executive Order 12866 (58 FR 51,735, October 4, 1993), this action is a “significant regulatory action” because it “raises novel legal or policy issues arising out of legal mandates”. Accordingly, the EPA submitted this action to the OMB for review under Executive Orders 12866 and 13563 (76 FR 3821, January 21, 2011) and any changes made in response to the OMB recommendations have been documented in the docket for this rulemaking.

*For purposes of this summary, we present climate benefits from CO₂ that were estimated using the model average social cost of carbon (SCC) at a 3% discount rate. We emphasize the importance and value of considering the full range of SCC values, however, which include the model average at 2.5% and 5%, and the 95th percentile at 3%. Similarly, we summarize the health co-benefits in this synopsis at a 3% discount rate. We provide estimates based on additional discount rates in the RIA.*
action. In addition, the EPA prepared an analysis of the potential costs and benefits associated with this action. This analysis is contained in Chapter 9 of the Regulatory Impact Analysis for Emission Guidelines for Greenhouse Gas Emissions from Existing Stationary Sources: Electric Utility Generating Units.

As explained in the RIA for this proposed rule, in the period of analysis (through 2025) the EPA anticipates few, if any, sources will trigger either the modification or the reconstruction provisions proposed. Because there have been a few units that have notified the EPA of NSPS modifications in the past, we have conducted an illustrative analysis of the costs and benefits for a representative unit that is included in Chapter 9 of the RIA.

B. Paperwork Reduction Act

This proposed action does not impose an information collection burden under the provisions of the Paperwork Reduction Act, 44 U.S.C. 3501 et seq. Burden is defined at 5 CFR 1320.3(b). As previously stated, the EPA expects, few, if any, modified or reconstructed EGUs in the period of analysis. Specifically, the EPA believes it unlikely that fossil fuel-fired electric utility steam generating units (utility boilers and IGCC units) or stationary combustion turbines will take actions that would constitute modifications
or reconstructions as defined under the EPA’s NSPS regulations. Accordingly, this proposed action is not anticipated to impose any information collection burden over the 3-year period covered by this ICR. We have estimated, however, the information collection burden that would be imposed on an affected EGU if it was modified or reconstructed. The information collection requirements in this proposed rule have been submitted for approval to the Office of Management and Budget (OMB) under the Paperwork Reduction Act, 44 U.S.C. 3501 et seq. The Information Collection Request (ICR) document prepared by the EPA has been assigned the EPA ICR number 2465.03.

The EPA intends to codify the standards of performance in the same way for both this proposed action and the January 2014 proposal for new sources and is proposing the same recordkeeping and reporting requirements that were included in the January 2014 proposal. See 79 FR at 1,498/3 and 1,499/3. Although not anticipated, if an EGU were to modify or reconstruct, this proposed action would impose minimal information collection burden on affected sources beyond what those sources would already be subject to under the authorities of CAA parts 75 and 90.

97 The information collection requirements in the January 2014 proposal have been submitted for approval to the OMB under the Paperwork Reduction Act, 44 U.S.C. 3501 et seq. The ICR document prepared by the EPA for the January 2014 proposal has been assigned the EPA ICR number 2465.02.
98. The OMB has previously approved the information collection requirements contained in the existing part 75 and 98 regulations (40 CFR part 75 and 40 CFR part 98) under the provisions of the Paperwork Reduction Act, 44 U.S.C. 3501 et seq. and has assigned OMB control numbers 2060-0626 and 2060-0629, respectively. Apart from potential energy metering modifications to comply with net energy output based emission limits proposed in this action and certain reporting costs, which are mandatory for all owners/operators subject to CAA section 111 national emission standards, there would be no new information collection costs, as the information required by this proposed rule is already collected and reported by other regulatory programs. The recordkeeping and reporting requirements are specifically authorized by CAA section 114 (42 U.S.C. 7414). All information submitted to the EPA pursuant to the recordkeeping and reporting requirements for which a claim of confidentiality is made is safeguarded according to Agency policies set forth in 40 CFR part 2, subpart B.

Although, as stated above, the EPA expects few, if any, sources will trigger either the NSPS modification or reconstruction provisions that we are proposing, if an EGU were to modify or reconstruct during the 3-year period covered by this ICR, it is likely that an EGU’s energy metering equipment would need to be modified to comply with proposed net energy
output based CO₂ emission limits. Specifically, the EPA estimates that it would take approximately 3 working months for a technician to retrofit existing energy metering equipment to meet the proposed net energy output requirements. In addition, after modifications are made that enable a facility to measure net energy output, each EGU’s Data Acquisition System (DAS) would need to be upgraded to accommodate reporting of net energy output rate based emissions. A modified or reconstructed EGU would be required to prepare a quarterly summary report, which includes reporting of emissions and downtime, every 3 months. The reporting burden for such a unit (averaged over the first 3 years after the effective date of the standards) is estimated to be $17,217 and 205 labor hours. Estimated cost burden is based on 2013 Bureau of Labor Statistics (BLS) labor cost data. Average burden hours per response are estimated to be 47.3 hours and the average number of annual responses over the 3-year ICR period is 4.33 per year. Burden is defined at 5 CFR 1320.3(b).

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for the EPA's regulations in 40 CFR are listed in 40 CFR part 9.
To comment on the Agency's need for this information, the accuracy of the provided burden estimates, and any suggested methods for minimizing respondent burden, the EPA has established a public docket for this rule, which includes this ICR, under Docket ID number EPA-HQ-OAR-2013-0603. Submit any comments related to the ICR to the EPA and OMB. See ADDRESSES section at the beginning of this notice for where to submit comments to the EPA. Send comments to OMB at the Office of Information and Regulatory Affairs, Office of Management and Budget, 725 17th Street, NW, Washington, DC 20503, Attention: Desk Officer for the EPA. Since OMB is required to make a decision concerning the ICR between 30 and 60 days after [INSERT DATE OF PUBLICATION IN THE FEDERAL REGISTER], a comment to OMB is best assured of having its full effect if OMB receives it by [INSERT DATE 30 DAYS AFTER PUBLICATION IN THE FEDERAL REGISTER]. The final rule will respond to any OMB or public comments on the information collection requirements contained in this proposal.

The information collection requirements in the January 2014 proposal have been submitted for approval to the OMB under the Paperwork Reduction Act, 44 U.S.C. 3501 et seq. The ICR document prepared by the EPA for the January 2014 proposal has been assigned the EPA ICR number 2465.02.

C. Regulatory Flexibility Act
The Regulatory Flexibility Act (RFA) generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small organizations, and small governmental jurisdictions.

For purposes of assessing the impacts of this rule on small entities, small entity is defined as:

1. A small business that is defined by the SBA’s regulations at 13 CFR 121.201 (for the electric power generation industry, the small business size standard is an ultimate parent entity with less than 750 employees. The NAICS codes for the affected industry are in Table 4 below);

2. A small governmental jurisdiction that is a government of a city, county, town, school district or special district with a population of less than 50,000; and

3. A small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field.

Table 4: Potentially Regulated Categories and Entities

Comment [A44]: Should this include “tribal governments” as Table 2 (pg. 31) does?

EPA Response: For purposes of the RFA, states and tribal governments are not considered small governments.

We have removed the table because small entity (including small governmental jurisdiction) is defined immediately above and, as pointed out, Table 2 lists potentially regulated entities, in general.
<table>
<thead>
<tr>
<th>Category</th>
<th>NAICS Code</th>
<th>Examples of Potentially Regulated Entities</th>
</tr>
</thead>
<tbody>
<tr>
<td>Industry</td>
<td>221112</td>
<td>Fossil fuel electric power generating units.</td>
</tr>
<tr>
<td>State/Local Government</td>
<td>221112b</td>
<td>Fossil fuel electric power generating units owned by municipalities.</td>
</tr>
</tbody>
</table>

- Include NAICS categories for source categories that own and operate electric power generating units (includes boilers and stationary combined cycle combustion turbines).
- State or local government-owned and operated establishments are classified according to the activity in which they are engaged.

After considering the economic impacts of this proposed rule on small entities, I certify that this action will not have a significant economic impact on a substantial number of small entities.

The EPA expects few, if any, modified utility boilers, IGCC units, or stationary combustion turbines in the period of analysis. An NSPS modification is defined as a physical or operational change that increases the source’s maximum achievable hourly rate of emissions. The EPA does not believe that there are likely to be EGUs that will take actions that would constitute modifications as defined under the EPA’s NSPS regulations.

Because there have been a limited number of units that have notified the EPA of NSPS modifications in the past, the RIA for
this proposed rule includes an illustrative analysis of the costs and benefits for a representative unit.

Based on the analysis, the EPA estimates that this proposed rule could result in CO₂ emission changes, quantified benefits, or costs for a hypothetical unit that triggered the modification provision. However, we do not anticipate this proposed rule would impose significant costs on those sources, including any that are owned by small entities.

In addition, the EPA expects few, if any, reconstructed fossil fuel-fired electric utility steam generating units (utility boilers and IGCC units) or stationary combustion turbines in the period of analysis. Reconstruction occurs when a single project replaces components or equipment in an existing facility and exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility. Due to the limited data available on reconstructions, it is not possible to conduct a representative illustrative analysis of what costs and benefits might result from this proposal in the unlikely case that a unit were to reconstruct. However, based on the low number of previous reconstructions and the BSER determination based on the most efficient available generating technology, we would expect this proposal to result in no significant CO₂ emission changes, quantified benefits, or costs for NSPS reconstructions. Accordingly, there are no
anticipated economic impacts as a result of the proposed standards for reconstructed EGUs.

Nevertheless, the EPA is aware that there is substantial interest in the proposed rule among small entities (municipal and rural electric cooperatives). As summarized in section II.G. of this preamble, the EPA has conducted an unprecedented amount of stakeholder outreach. As part of that outreach, agency officials participated in many meetings with individual utilities as well as meetings with electric utility associations. Specifically, the EPA Administrator, Gina McCarthy, participated in separate meetings with both the National Rural Electric Cooperative Association (NRECA) and the American Public Power Association (APPA). The meetings brought together leaders of the rural cooperatives and public power utilities from across the country. The Administrator discussed and exchanged information on the unique challenges, in particular the financial structure, of NRECA and APPA member utilities. A detailed discussion of the stakeholder outreach is included in the preamble to the emission guidelines for existing affected electric utility generating units being proposed in a separate action.

In addition, as described in the RFA section of the preamble to the proposed standards of performance for GHG emissions from new EGUs (79 FR 1499 and 1500, January 8, 2014),
the EPA conducted outreach to representatives of small entities while formulating the provisions of the proposed standards. Although only new EGUs would be affected by those proposed standards, the outreach regarded planned actions for new, reconstructed, modified and existing sources.

While formulating the provisions of this proposed rule, the EPA considered the input provided over the course of the stakeholder outreach. We invite comments on all aspects of this proposal and its impacts, including potential impacts on small entities.

D. Unfunded Mandates Reform Act

This proposed rule does not contain a federal mandate that may result in expenditures of $100 million or more for state, local and tribal governments, in the aggregate, or the private sector in any 1 year. As previously stated, the EPA expects few, if any, modified or reconstructed fossil fuel-fired electric utility steam generating units (utility boilers and IGCC units) or stationary combustion turbines in the period of analysis. Accordingly, this proposed rule is not subject to the requirements of sections 202 or 205 of UMRA.

This proposed rule is also not subject to the requirements of section 203 of UMRA because it contains no regulatory requirements that might significantly or uniquely affect small governments.
In light of the interest among governmental entities, the EPA initiated consultations with governmental entities while formulating the provisions of the proposed standards for newly constructed EGUs. This outreach regarded planned actions for new, reconstructed, modified and existing sources. As described in the UMRA discussion in the preamble to the proposed standards of performance for GHG emissions from new EGUs (79 FR 1500 and-1501, January 8, 2014), the EPA consulted with the following 10 national organizations representing state and local elected officials: (1) National Governors Association; (2) National Conference of State Legislatures, (3) Council of State Governments, (4) National League of Cities, (5) U.S. Conference of Mayors, (6) National Association of Counties, (7) International City/County Management Association, (8) National Association of Towns and Townships, (9) County Executives of America, and (10) Environmental Council of States. On February 26, 2014, the EPA re-engaged with those governmental entities to provide a pre-proposal update on the emission guidelines for existing EGUs and emission standards for modified and reconstructed EGUs.

While formulating the provisions of these proposed standards, the EPA also considered the input provided over the course of the extensive stakeholder outreach conducted by the EPA (see section II.G. of this preamble).
This proposed 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, as specified in Executive Order 13132. This proposed action would not impose substantial direct compliance costs on state or local governments, nor would it preempt state law. Thus, Executive Order 13132 does not apply to this action.

However, as described in the Federalism discussion in the preamble to the proposed standards of performance for GHG emissions from new EGUs (79 FR 1501, January 8, 2014), the EPA consulted with state and local officials in the process of developing the proposed standards for newly constructed EGUs. This outreach regarded planned actions for new, reconstructed, modified and existing sources. The EPA engaged 10 national organizations representing state and local elected officials. The UMRA discussion in the preamble to the proposed standards of performance for GHG emissions from new EGUs (79 FR 1500 and 1501, January 8, 2014) includes a description of the consultation. In addition, on February 26, 2014, the EPA re-engaged with those governmental entities to provide a pre-proposal update on the emission guidelines for existing EGUs and
emission standards for modified and reconstructed EGUs. While formulating the provisions of these proposed standards, the EPA also considered the input provided over the course of the extensive stakeholder outreach conducted by the EPA (see section II.G. of this preamble). In the spirit of Executive Order 13132 and consistent with the EPA policy to promote communications between the EPA and state and local governments, the EPA specifically solicits comment on this proposed action from state and local officials.

F. Executive Order 13175, Consultation and Coordination with Indian Tribal Governments

This action does not have tribal implications, as specified in Executive Order 13175 (65 FR 67249, November 9, 2000). It would neither impose substantial direct compliance costs on tribal governments, nor preempt Tribal law. This proposed rule would impose requirements on owners and operators of reconstructed and modified EGUs. 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 proposal 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 expects few, if any,
modified or reconstructed EGUs in the period of analysis. Thus, Executive Order 13175 does not apply to this action.

Although Executive Order 13175 does not apply to this action, the EPA conducted outreach to tribal environmental staff and offered consultation with tribal officials in developing this action. Because the EPA is aware of tribal interest in carbon pollution standards for the power sector, prior to proposal of GHG standards for new power plants, the EPA offered consultation with tribal officials early in the process of developing the proposed regulation to permit them to have meaningful and timely input into its development. The EPA’s consultation regarded planned actions for new, reconstructed, modified, and existing sources. The Consultation and Coordination with Indian Tribal Governments discussion in the preamble to the proposed standards of performance for GHG emissions from new EGUs (79 FR 1501, January 8, 2014) includes a description of that consultation.

During development of this proposed regulation, consultation letters were sent to 584 tribal leaders. The letters provided information regarding the EPA’s development of both the NSPS for modified and reconstructed EGUs and emission guidelines for existing EGUs and offered consultation. None have requested consultation. Tribes were invited to participate in the national informational webinar held August 27, 2013, and to
which tribes were invited. In addition, a consultation/outreach meeting was held on September 9, 2013, with tribal representatives from some of the 584 tribes. The EPA also met with tribal environmental staff with the National Tribal Air Association, by teleconference, on July 25, 2013, and December 19, 2013. In those teleconferences, the EPA provided background information on the GHG emission guidelines to be developed and a summary of issues being explored by the agency. Additional detail regarding this stakeholder outreach is included in the preamble to the emission guidelines for existing affected electric utility generating units being proposed in a separate action today. The EPA also held a series of listening sessions prior to proposal of GHG standards for new power plants. Tribes participated in a session on February 17, 2011, with the state agencies, as well as in a separate session with tribes on April 20, 2011.

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

G. Executive Order 13045, Protection of Children From Environmental Health Risks and Safety Risks
The EPA interprets Executive Order 13045 (62 FR 19885, April 23, 1997) as applying to those regulatory actions that concern health or safety risks, such that the analysis required under section 5-501 of the Order has the potential to influence the regulation. This action is not subject to Executive Order 13045 because it is based solely on technology performance.

This proposed action is not a “significant energy action” as defined in Executive Order 13211 (66 FR 28355, May 22, 2001) because it is not likely to have a significant adverse effect on the supply, distribution, or use of energy. As previously stated, the EPA expects few, if any, reconstructed or modified EGUs in the period of analysis and this proposed action is not anticipated to have impacts on emissions, costs or energy supply decisions for the affected electric utility industry to be minimal as a result.

Section 12(d) of the NTTAA of 1995 (Public Law No. 104-113; 15 U.S.C. 272 note) directs the EPA to use VCS in their regulatory and procurement activities unless to do so would be inconsistent with applicable law or otherwise impractical. VCS are technical standards (e.g., materials specifications, test methods, sampling procedures, business practices) developed or
adopted by one or more voluntary consensus bodies. The NTTAA directs the EPA to provide Congress, through annual reports to the OMB, with explanations when an agency does not use available and applicable VCS.

This proposed rulemaking involves technical standards. The EPA proposes to use the following standards in this proposed rule: ASTM_D5287388-12-08 (Standard Classification of Coals by Rank Standard Practice for Automatic Sampling of Caceous Fuels), ASTM_D396-13c4057-06 (Standard Specification for Fuel Oils Standard Practice for Manual Sampling of Petroleum and Petroleum Products), and ASTM_D4177-95(2010)975-14 (Standard Specification for Diesel Fuel Oils Standard Practice for Automatic Sampling of Petroleum and Petroleum Products), D3699-13b (Standard Specification for Kerosene), D6751-12 (Standard Specification for Biodiesel Fuel Blend Stock (B100) for Middle Distillate Fuels), ASTM_D7467-13 (Standard Specification for Diesel Fuel Oil, Biodiesel Blend (B6 to B20)), and ANSI_C12.20 (American National Standard for Electricity Meters - 0.2 and 0.5 Accuracy Classes). The EPA is proposing use of Appendices A, B, D, F and G to 40 CFR part 75; these Appendices contain standards that have already been reviewed under the NTTAA.

The EPA welcomes comments on this aspect of the proposed rulemaking and, specifically, invites the public to identify
potentially-applicable VCS and to explain why such standards should be used in this action.

**J. Executive Order 12898: Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations**

Executive Order 12898 (59 FR 7629, February 16, 1994) establishes federal executive policy on environmental justice. Its main provision directs federal agencies, to the greatest extent practicable and permitted by law, to make environmental justice part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies and activities on minority populations and low-income populations in the U.S.

This proposed rule limits GHG emissions from modified and reconstructed fossil fuel-fired electric utility steam generating units (utility boilers and IGCC units) and stationary combustion turbines by establishing national emission standards for CO₂. The EPA has determined that this proposed rule would not result in disproportionately high and adverse human health or environmental effects on minority, low-income and indigenous populations because it does not affect the level of protection provided to human health or the environment. As previously stated, the EPA expects few, if any, modified or reconstructed fossil fuel-fired electric utility steam generating units
(utility boilers and IGCC units) or stationary combustion turbines in the period of analysis.

XII. Statutory Authority

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

40 CFR Part 60

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

Dated: MONTH XX, 2014.

Gina McCarthy,
Administrator.
The Environmental Protection Agency proposed rule amending 40 CFR parts 60, 70, 71, which was published on January 8, 2014, (79 FR 1430), January 8, 2014, the EPA proposed amendments to the regulatory text of subparts Da and KKKK and, as an alternative to amending subparts Da and KKKK, to create a new subpart (subpart TTTT) to include GHG standards for new EGUs. To facilitate understanding the amendments being proposed in this proposal, we are providing a Technical Support Document (TSD) in the docket for this rulemaking in track changes that shows the proposed amendments considering the amendments proposed in previous the January 8, 2014, proposal.

Comment [A48]: General Comment: General Tribal implications should be clarified in the regulatory text where appropriate. For example, the text currently only notes that tribal agencies can implement/enforce in § 60.5575, pg. 35).

EPA: We will clarify the regulatory text as appropriate.