ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[EPA–HQ–OAR–2024–0419; FRL–11542–01–OAR]

RIN 2060–AW21

Review of New Source Performance Standards for Stationary Combustion Turbines and Stationary Gas Turbines

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: The Environmental Protection Agency (EPA) is proposing amendments to the Standards of Performance for new, modified, and reconstructed stationary combustion turbines and stationary gas turbines based on a review of available control technologies for limiting emissions of criteria air pollutants. This review of the new source performance standards (NSPS) is required by the Clean Air Act (CAA). As a result of this review, the EPA is proposing to establish size-based subcategories for new, modified, and reconstructed stationary combustion turbines that also recognize distinctions between those that operate at varying loads or capacity factors and those firing natural gas or non-natural gas fuels. In general, the EPA is proposing that combustion controls with the addition of post-combustion selective catalytic reduction (SCR) is the best system of emission reduction (BSER) for limiting nitrogen oxide (NO_X) emissions from this source category, with certain, limited exceptions. Based on the application of this BSER and other updates in technical information, the EPA is proposing to lower the NO_X standards of performance for most of the stationary combustion turbines included in this source category. In addition, for new, modified, and reconstructed stationary combustion turbines that fire or co-fire hydrogen, the EPA is proposing to ensure that those sources are subject to the same level of control for NO_X emissions as sources firing natural gas or non-natural gas fuels, depending on the percentage of hydrogen fuel being utilized. The EPA is proposing to maintain the current standards for sulfur dioxide (SO_2) emissions, because after reviewing the current SO_2 standards, we propose to find that the use of low-sulfur fuels remains the BSER. Finally, the Agency is proposing amendments to address specific technical and editorial issues to clarify the existing regulations.

DATES:

Comments. Comments must be received on or before March 13, 2025. Comments on the information collection provisions submitted to the Office of Management and Budget (OMB) under the Paperwork Reduction Act (PRA) are best assured of consideration by OMB if OMB receives a copy of your comments on or before January 13, 2025. For specific instructions, please see the PRA discussion in the *Statutory and Executive Order Reviews* section of this document.

Public Hearing. If anyone contacts us requesting a public hearing on or before December 18, 2024, we will hold a virtual public hearing. See **SUPPLEMENTARY INFORMATION** for information on requesting and registering for a public hearing.

ADDRESSES: You may send comments, identified by Docket ID No. EPA–HQ–OAR–2024–0419, by any of the following methods:

- *Federal eRulemaking Portal: https://www.regulations.gov* (our preferred method). Follow the online instructions for submitting comments.
- *Email: a-and-r-docket@epa.gov.* Include Docket ID No. EPA–HQ–OAR–2024–0419 in the subject line of the message.
- *Fax:* (202) 566–9744. Attention Docket ID No. EPA–HQ–OAR–2024–0419.
- *Mail:* U.S. Environmental Protection Agency, EPA Docket Center, Docket ID No. EPA–HQ–OAR–2024–0419, Mail Code 28221T, 1200 Pennsylvania Avenue NW, Washington, DC 20460.
- *Hand/Courier Delivery:* EPA Docket Center, WJC West Building, Room 3334, 1301 Constitution Avenue NW, Washington, DC 20004. The Docket Center's hours of operation are 8:30 a.m.–4:30 p.m., Monday–Friday (except Federal Holidays).

Instructions: All submissions received must include the Docket ID No. for this rulemaking. Comments received may be posted without change to *https://www.regulations.gov,* including any personal information provided. For detailed instructions on sending comments and additional information on the rulemaking process, see the **SUPPLEMENTARY INFORMATION** section below.

FOR FURTHER INFORMATION CONTACT: John Ashley, Sector Policies and Programs Division (D243–02), Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, 109 T.W. Alexander Drive, P.O. Box 12055 RTP, North Carolina 27711; telephone number: (919) 541–1458; and email address: *ashley.john@epa.gov.*

SUPPLEMENTARY INFORMATION:

Participation in virtual public hearing. To request a virtual public hearing, contact the public hearing team at (888) 372–8699 or by email at *SPPDpublichearing@epa.gov.* If requested, the public hearing will be held via virtual platform. The EPA will announce the date of the hearing and additional details on the virtual public hearing at *https://www.epa.gov/stationary-sources-air-pollution/stationary-gas-and-combustion-turbines-new-source-performance.* The hearing will convene at 11:00 a.m. Eastern Time (ET) and will conclude at 4:00 p.m. ET. The EPA may close a session 15 minutes after the last pre-registered speaker has testified if there are no additional speakers.

The EPA will begin pre-registering speakers for the hearing no later than 1 business day after a request has been received. The EPA will accept registrations on an individual basis. To register to speak at the virtual hearing, please use the online registration form available at *https://www.epa.gov/stationary-sources-air-pollution/stationary-gas-and-combustion-turbines-new-source-performance* or contact the public hearing team at (888) 372–8699 or by email at *SPPDpublichearing@epa.gov.* The last day to pre-register to speak at the hearing will be December 26, 2024. Prior to the hearing, the EPA will post a general agenda that will list pre-registered speakers at: *https://www.epa.gov/stationary-sources-air-pollution/stationary-gas-and-combustion-turbines-new-source-performance.*

The EPA will make every effort to follow the schedule as closely as possible on the day of the hearing; however, please plan for the hearing to run either ahead of schedule or behind schedule.

Each commenter will have 4 minutes to provide oral testimony. The EPA encourages commenters to submit a copy of their oral testimony as written comments electronically to the rulemaking docket.

The EPA may ask clarifying questions during the oral presentations but will not respond to the presentations at that time. Written statements and supporting information submitted during the comment period will be considered with the same weight as oral testimony and supporting information presented at the public hearing.

Please note that any updates made to any aspect of the hearing will be posted online at *https://www.epa.gov/stationary-sources-air-pollution/stationary-gas-and-combustion-turbines-new-source-performance.*

While the EPA expects the hearing to go forward as described in this section, please monitor our website or contact the public hearing team at (888) 372–8699 or by email at *SPPDpublichearing@epa.gov* to determine if there are any updates. The EPA does not intend to publish a document in the **Federal Register** announcing updates.

If you require the services of a translator or a special accommodation such as audio description, please pre-register for the hearing with the public hearing team and describe your needs by December 20, 2024. The EPA may not be able to arrange accommodations without advanced notice.

Docket. The EPA has established a docket for this rulemaking under Docket ID No. EPA–HQ–OAR–2024–0419. All documents in the docket are listed in the *Regulations.gov* index. Although listed in the index, some information is not publicly available, *e.g.,* Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the internet and will be publicly available only as pdf versions that can only be accessed on the EPA computers in the docket office reading room. Certain databases and physical items cannot be downloaded from the docket but may be requested by contacting the docket office at (202) 566–1744. The docket office has up to 10 business days to respond to these requests. With the exception of such material, publicly available docket materials are available electronically in *Regulations.gov*.

Written Comments. Submit your comments, identified by Docket ID No. EPA–HQ–OAR–2024–0419, at *https://www.regulations.gov* (our preferred method), or the other methods identified in the **ADDRESSES** section. Once submitted, comments cannot be edited or removed from the docket. The EPA may publish any comment received to its public docket. Do not submit to EPA's docket at *https://www.regulations.gov* any information you consider to be CBI or other information whose disclosure is restricted by statute. This type of information should be submitted as discussed in the *Submitting CBI* section of this document.

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

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

Submitting CBI. Do not submit information containing CBI to the EPA through *https://www.regulations.gov.* Clearly mark the part or all of the information that you claim to be CBI. For CBI information on any digital storage media that you mail to the EPA, note the docket ID, mark the outside of the digital storage media as CBI, and identify electronically within the digital storage media the specific information that is claimed as CBI. In addition to one complete version of the comments that includes information claimed as CBI, you must submit a copy of the comments that does not contain the information claimed as CBI directly to the public docket through the procedures outlined in the *Written Comments* section of this document. If you submit any digital storage media that does not contain CBI, mark the outside of the digital storage media clearly that it does not contain CBI and note the docket ID. Information not marked as CBI will be included in the public docket and the EPA's electronic public docket without prior notice. Information marked as CBI will not be disclosed except in accordance with procedures set forth in 40 Code of Federal Regulations (CFR) part 2.

Our preferred method to receive CBI is for it to be transmitted electronically using email attachments, File Transfer Protocol (FTP), or other online file sharing services (*e.g.,* Dropbox, OneDrive, Google Drive). Electronic submissions must be transmitted directly to the Office of Air Quality Planning and Standards (OAQPS) CBI Office at the email address *oaqpscbi@epa.gov,* and as described above, should include clear CBI markings and note the docket ID. If assistance is needed with submitting large electronic files that exceed the file size limit for email attachments, and if you do not have your own file sharing service, please email *oaqpscbi@epa.gov* to request a file transfer link. If sending CBI information through the postal service, please send it to the following address: U.S. EPA, Attn: OAQPS Document Control Officer, Mail Drop: C404–02, 109 T.W. Alexander Drive, P.O. Box 12055, Research Triangle Park, North Carolina 27711, Attention Docket ID No. EPA–HQ–OAR–2024–0419. The mailed CBI material should be double wrapped and clearly marked. Any CBI markings should not show through the outer envelope.

Preamble acronyms and abbreviations. Throughout this document the use of ''we,'' ''us,'' or ''our'' is intended to refer to the EPA. We use multiple acronyms and terms in this preamble. While this list may not be exhaustive, to ease the reading of this preamble and for reference purposes, the EPA defines the following terms and acronyms here:

ANSI American National Standards Institute
ASTM American Society for Testing and Materials
BACT best achievable control technology
BPT benefit-per-ton
BSER best system of emission reduction
Btu British thermal unit
CAA Clean Air Act
CBI Confidential Business Information
CDX Central Data Exchange
CEDRI Compliance and Emissions Data Reporting Interface
CFR Code of Federal Regulations
CHP combined heat and power
CO carbon monoxide
DLE dry low-emission
DLN dry low NO_X
EGU electric generating unit
EJ environmental justice
EPA Environmental Protection Agency
ERT Electronic Reporting Tool
FR Federal Register
FTP file transfer protocol
GE General Electric
GHG greenhouse gas
GJ gigajoule(s)
gr grains
HAP hazardous air pollutant
HHV higher heating value
HRSG heat recovery steam generator
ICR information collection request
kW kilowatt
LAER lowest achievable emission rate

lb/MWh pounds per megawatt-hour
lb/MMBtu pounds per million British thermal units
mg/scm milligrams per standard cubic meter
MJ megajoules
MMBtu/h million British thermal units per hour
MW megawatt
MWh megawatt-hour
NAICS North American Industry Classification System
NEI National Emissions Inventory
NESHAP national emission standards for hazardous air pollutants
NETL National Energy Technology Laboratory
ng/J nanograms per joule
NO_X nitrogen oxide
NSPS new source performance standards
NSR New Source Review
NTTAA National Technology Transfer and Advancement Act
O_2 oxygen
O&M operating and maintenance
OAQPS Office of Air Quality Planning and Standards
OMB Office of Management and Budget
PDF portable document format
PM particulate matter
$PM_{2.5}$ particulate matter (diameter less than or equal to 2.5 micrometers)
ppm parts per million
ppmv parts per million by volume
ppmw parts per million by weight
PRA Paperwork Reduction Act
RACT reasonably available control technology
RBLC RACT/BACT/LAER Clearinghouse
RFA Regulatory Flexibility Act
RIA regulatory impact analysis
scf standard cubic feet
scm standard cubic meter
SCR selective catalytic reduction
SO_2 sulfur dioxide
SSM startup, shutdown, and malfunction
ULSD ultra-low sulfur diesel
UMRA Unfunded Mandates Reform Act
U.S.C. United States Code
VCS voluntary consensus standard
VOC volatile organic compound(s)
WFR water-to-fuel ratio

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

I. General Information

A. Does this action apply to me?

The source category that is the subject of this proposal is composed of any industry using a newly constructed, modified, or reconstructed stationary combustion turbine as defined in section II.B of this preamble and regulated under Clean Air Act (CAA) section 111, New Source Performance Standards. Based on the number of sources of stationary combustion turbines listed in the 2020 National Emissions Inventory (NEI), most, but not all, are accounted for by the following 2022 North American Industry Classification System (NAICS) codes. These include 221112 (Fossil Fuel Electric Power Generation), 486210 (Pipeline Transportation of Natural Gas), 22111 (Electric Power Generation), 211130 (Natural Gas Extraction), 221210 (Natural Gas Distribution), 325110 (Petrochemical Manufacturing), and 2111 (Oil and Gas Extraction). The NAICS codes serve as a guide for readers outlining the entities that this proposed action is likely to affect. Please see the accompanying Regulatory Impact Analysis (RIA) in the docket for this proposed rulemaking for a complete list of potentially affected sources and their NAICS codes. The proposed standards, once promulgated, will be directly applicable to affected facilities that begin construction, reconstruction, or modification after the date of publication of the proposed standards in the **Federal Register**. Federal, State, local, and Tribal government entities that own and/or operate stationary combustion turbines subject to existing 40 Code of Federal Regulations (CFR) part 60, subparts GG or KKKK, or proposed 40 CFR part 60, subpart KKKKa, may be affected by these proposed amendments and standards.

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

In addition to being available in the docket, an electronic copy of this action is available via the internet at *https://www.epa.gov/stationary-sources-air-pollution/stationary-gas-and-combustion-turbines-new-source-performance.* Following publication in the **Federal Register**, the EPA will post the **Federal Register** version of the proposal and key technical documents at this same web page. In accordance with 5 U.S.C. 553(b)(4), a summary of this proposed rule may be found at Docket ID No. EPA–HQ–OAR–2024–0419 at *https://www.regulations.gov.*

Memoranda showing the edits that would be necessary to incorporate the changes to 40 CFR part 60, subparts GG and KKKK and 40 CFR part 60, subpart KKKKa proposed in this action are available in the docket. Following signature by the EPA Administrator, the EPA also will post a copy of this document to *https://www.epa.gov/stationary-sources-air-pollution/stationary-gas-and-combustion-turbines-new-source-performance.*

II. Background

A. What is the statutory authority for this action?

The EPA's authority for this proposed rule is CAA section 111, which governs the establishment of standards of performance for stationary sources. Section 111(b)(1)(A) of the CAA requires the EPA Administrator to list categories of stationary sources that in the Administrator's judgment cause or contribute significantly to air pollution that may reasonably be anticipated to endanger public health or welfare. The EPA must then issue performance standards for new (and modified or reconstructed) sources in each source category pursuant to CAA section 111(b)(1)(B). These standards are referred to as new source performance standards, or NSPS. The EPA has the authority to define the scope of the source categories, determine the pollutants for which standards should be developed, set the emission level of the standards, and distinguish among classes, types, and sizes within categories in establishing the standards.

CAA section 111(b)(1)(B) requires the EPA to ''at least every 8 years review and, if appropriate, revise'' new source performance standards. However, the Administrator need not review any such standard if the ''Administrator determines that such review is not appropriate in light of readily available information on the efficacy'' of the standard. When conducting a review of an existing performance standard, the EPA has the discretion and authority to add emission limits for pollutants or emission sources not currently regulated for that source category.

In setting or revising a performance standard, CAA section 111(a)(1) provides that performance standards are to reflect ''the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.'' The term ''standard of performance'' in CAA section 111(a)(1) makes clear that the EPA is to determine both the best system of emission reduction (BSER) for the regulated sources in the source category and the degree of emission limitation achievable through application of the BSER. The EPA must then, under CAA section 111(b)(1)(B), promulgate standards of performance for new sources that reflect that level of stringency. CAA section 111(b)(5) generally precludes the EPA from prescribing a particular technological system that must be used to comply with a standard of performance. Rather, sources can select any measure or combination of measures that will achieve the standard.

Pursuant to the definition of new source in CAA section 111(a)(2), standards of performance apply to facilities that begin construction, reconstruction, or modification after the date of publication of the proposed standards in the **Federal Register**. Under CAA section 111(a)(4), ''modification'' means any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted. Changes to an existing facility that do not result in an increase in emissions are not considered modifications. Under the provisions in 40 CFR 60.15, reconstruction means the replacement of components of an existing facility such 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. Pursuant to CAA section 111(b)(1)(B), the standards of performance or revisions thereof shall become effective upon promulgation.

B. What is this source category?

Sources subject to the proposed NSPS are stationary combustion turbines with a design base load rating (*i.e.,* maximum heat input at ISO conditions) equal to or greater than 10.7 gigajoules per hour (GJ/h) (10 million British thermal units per hour (MMBtu/h)),[1] based on the higher heating value (HHV) of the fuel, that commence construction, modification, or reconstruction after December 13, 2024. A stationary combustion turbine is defined as all equipment, including but not limited to the combustion turbine; the fuel, air, lubrication, and exhaust gas systems; the control systems (except emission control equipment); the heat recovery system (including heat recovery steam generators (HRSG) and duct burners); and any ancillary components and sub-components comprising any simple cycle, regenerative/recuperative cycle, and combined cycle stationary combustion turbine, and any combined heat and power (CHP) stationary combustion turbine-based system. The source is ''stationary'' because the combustion turbine is not self-propelled or intended to be propelled while performing its function. It may, however, be mounted on a vehicle for portability.

C. What are the current NSPS requirements?

The NSPS for stationary combustion turbines includes standards of performance to limit emissions of nitrogen oxide (NO_X) and sulfur dioxide (SO_2). The EPA last revised the NSPS on July 6, 2006, and promulgated 40 CFR part 60, subpart KKKK, which is applicable to stationary combustion turbines for which construction, modification, or reconstruction was commenced after February 18, 2005 (71 FR 38482). Standards of performance for the source category of stationary gas turbines were originally promulgated in 40 CFR part 60, subpart GG (44 FR 52792; September 10, 1979) and only apply to sources that were new prior to 2005.

The NO_X standards in subpart KKKK are based on the application of combustion controls (as the best system of emission reduction) and allow the turbine owner or operator the choice of meeting a concentration-based emission standard or an output-based emission standard. The concentration-based emission limits are in units of parts per million by volume dry (ppmvd) at 15 percent oxygen (O_2).[2] The output-based emission limits are in units of mass per unit of useful recovered energy, nanograms per Joule (ng/J) or pounds per megawatt-hour (lb/MWh). Each NO_X limit in subpart KKKK is based on the application of combustion controls as the BSER, but individual standards may differ for individual subcategories of combustion turbines based on the following factors: the fuel input rating at base load, the fuel used, the application, the load, and the location of the turbine. The fuel input rating of the turbine does not include any supplemental fuel input to the heat recovery system and refers to the rating of the combustion turbine itself.

Specifically, in subpart KKKK, the EPA identifies 14 subcategories of stationary combustion turbines and establishes NO_X emission limits for each. The current size-based subcategories include turbines with a design heat input rating of less than or equal to 50 MMBtu/h, those with a design heat input rating of greater than 50 MMBtu/h and less than or equal to 850 MMBtu/h, and those with a design heat input rating greater than 850 MMBtu/h. There are separate

[1] The base load rating is based on the heat input to the combustion turbine engine. Any additional heat input from duct burners used with heat recovery steam generating (HRSG) units or fuel preheaters is not included in the heat input value used to determine the applicability of this subpart to a given stationary combustion turbine. However, this subpart does apply to emissions from any HRSG and duct burners that are associated with a combustion turbine subject to this subpart.

[2] Throughout this document, all references to parts per million (ppm) NO_X are intended to be interpreted as parts per million by volume dry (ppmvd) at 15 percent O_2, unless otherwise noted.

subcategories for combustion turbines operating at part load, for modified and reconstructed combustion turbines, heat recovery units operating independent of the combustion turbine, and turbines operating at low ambient temperatures. A specific NO_X performance standard is identified for each of the 14 subcategories, and the limits range from 15 ppm to 150 ppm (*see* Table 1: NO_X Emission Standards; 71 FR 38483, July 6, 2006).

The standards of performance for SO_2 emissions in subpart KKKK reflect the use of low-sulfur fuels. The fuel sulfur content limit is 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for combustion turbines located in continental areas and 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input in noncontinental areas. This is approximately equivalent to 0.05 percent sulfur by weight (500 parts per million by weight (ppmw)) for fuel oil in continental areas and 0.4 percent sulfur by weight (4,000 ppmw) for fuel oil in noncontinental areas, respectively. Subpart KKKK also includes an optional output-based SO_2 standard that limits the discharge into the atmosphere of any gases that contain SO_2 in excess of 110 ng/J (0.90 lb/MWh) gross energy output for turbines located in continental areas and 780 ng/J (6.2 lb/MWh) gross energy output for turbines located in noncontinental areas.

Thousands of stationary combustion turbines are operating across numerous industrial sectors. In the utility sector alone, there are approximately 3,400 existing stationary combustion turbines.[3] Each of these affected sources is subject to either subpart KKKK or subpart GG.

D. What data and information were used to support this action?

The Agency analyzed hourly NO_X emissions data reported to the EPA's Clean Air Markets Program Data (CAMPD) under 40 CFR part 75 and other data and information available in the Energy Information Administration's (EIA) and the EPA's databases. In addition, the Agency reviewed other available information sources to determine whether there have been developments in practices, processes, or control technologies by stationary combustion turbines. These include the following:

• Air permit limits and selected compliance options from permits that were available online. Not all States provide online access to air permits, but the EPA was able to obtain and review State permits for approximately 70 stationary combustion turbines that are currently subject to subpart KKKK to inform the BSER technology review and obtain other relevant information about the source category, such as monitoring approaches applied.[4]

• Combustion turbine manufacturer specifications sheets for NO_X and other criteria pollutant emissions for common combustion turbine makes and models.[5]

• Communication with combustion turbine manufacturers, including Siemens, General Electric, Mitsubishi, and Solar Turbines. The Agency also communicated with the Gas Turbine Association (GTA), which represents industries in the affected NAICS categories and their members. Discussions focused on current combustion control technologies to reduce NO_X emissions as well as the cost effectiveness of post-combustion SCR for certain sizes and models of turbines.

• Search of the Agency's Reasonably Available Control Technology (RACT)/Best Available Control Technology (BACT)/Lowest Achievable Emission Rate (LAER) Clearinghouse (RBLC) database.[6]

A variety of sources were used to compile a list of existing facilities constructed in the past 5 years that are subject to subpart KKKK. That list was used to estimate the approximate number of new sources that may be subject to this proposed rulemaking. The list was based on data collected from Form EIA–860,[7] the EPA's National Electric Energy Data System (NEEDS) database,[8] and information collected during the Agency's ongoing work to review the National Emission Standards for Hazardous Air Pollutants (NESHAP) for combustion turbines under 40 CFR part 63, subpart YYYY. Form EIA–860 contains information about currently operating and planned individual electric generators, which includes their location, prime mover, and capacity. NEEDS is an EPA database of electric generators that serves as a resource for modeling the sector. NEEDS includes source information about existing and planned units, information about the combustion turbines themselves, and data about their air emission controls. The list of sources compiled for the EPA's review of the NESHAP only includes combustion turbines that are located at major sources of toxic air emissions. These source lists are included in the docket for this proposal.

E. What outreach and engagement did the EPA conduct?

As part of this rulemaking, the EPA engaged and consulted with the public, including communities with environmental justice (EJ) concerns, and industry representatives, through several interactions. The EPA opened a non-regulatory docket[9] and posted framing questions intended to solicit specific public input about ways the Agency could design a broad approach to the regulation of greenhouse gases (GHGs) and other air pollutants from combustion turbines under CAA sections 111 and 112 that protects human health and the environment. Several stakeholders posted comments to the non-regulatory docket pertaining to the review of the NSPS and subpart KKKK. Those comments were reviewed as part of this proposed action.

The EPA also held a public policy forum on May 17, 2024, at the EPA headquarters in Washington, DC. The forum included a series of panels and interactive discussion sessions that provided an opportunity for the Agency to hear a broad range of views and exchange of ideas concerning upcoming proposed regulations impacting air pollution emissions from stationary combustion turbines. Although the focus of the public policy forum was to discuss the regulation of GHG emissions from stationary combustion turbines in the power sector, there was also some discussion of the 8-year review of the NSPS and standards of performance for criteria pollutant emissions, such as NO_X. The forum included a wide range of stakeholders as members of panel discussions, as part of the in-person audience and attending virtually. Key groups represented included: State and local air agencies, Tribal Nations, affected companies, representatives of the EJ community, technology vendors, environmental non-governmental organizations, and electric reliability organizations and industry trade groups.

[3] See the U.S. Environmental Protection Agency's (EPA) National Electric Energy Data System database. NEEDS rev 06–06–2024. Accessed at *https://www.epa.gov/power-sector-modeling/national-electric-energy-data-system-needs.*

[4] See the *Research Summary Memo* in the docket for this rulemaking for a summary of the results from this State permit search.

[5] See the *Combustion Turbine Manufacturer Specsheet Memo* in the docket for this rulemaking for a summary of the review of turbine manufacturers' specification sheets.

[6] U.S. Environmental Protection Agency (EPA). RACT/BACT/LAER Clearinghouse (RBLC). Available at *https://cfpub.epa.gov/rblc/.*

[7] U.S. Energy Information Administration (EIA). (June 12, 2024). Form EIA–860 data. Available at *https://www.eia.gov/electricity/data/eia860/.*

[8] See the U.S. Environmental Protection Agency's (EPA) National Electric Energy Data System database. NEEDS rev 06–06–2024. Accessed at *https://www.epa.gov/power-sector-modeling/national-electric-energy-data-system-needs.*

[9] See EPA–HQ–OAR–2024–0135, available at *https://www.regulations.gov.*

The EPA also consulted with representatives of State and local governments in the process of developing this action to permit them to have meaningful and timely input into their development. The EPA invited the following 10 national organizations representing State and local elected officials to a virtual meeting on August 15, 2024: (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. Also, the EPA invited air and utility professional groups who may have State and local government members, including the Association of Air Pollution Control Agencies; National Association of Clean Air Agencies; American Public Power Association; Large Public Power Council; National Rural Electric Cooperative Association; National Association of Regulatory Utility Commissioners; and National Association of State Energy Officials to participate in the meeting. The purpose of the consultation was to provide general background on the rulemaking, answer questions, and solicit input from State and local governments.

The EPA has also engaged with major combustion turbine manufacturers such as Siemens, General Electric, Mitsubishi, and Solar Turbines, as well as with industry trade groups such as the Gas Turbine Association (GTA), for assistance with some of the data collection efforts previously identified in section II.D. Specifically, this included updates on any technology developments and cost estimates that would impact turbine performance and/or criteria pollutant emissions for most new models of available combustion turbines.

F. How did the EPA consider environmental justice in the development of this action?

Consistent with applicable Executive orders and EPA policy, the Agency carefully considered the potential implications of this proposed action on communities with EJ concerns. As part of the regulatory development process for this rulemaking, and consistent with feedback we received during the development of the final *New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule* (*i.e.,* the Carbon Pollution Standards),[10] the EPA continued its outreach with interested parties, including communities with EJ concerns. These opportunities gave the EPA a chance to hear directly from the public, including from communities potentially impacted by this proposed rule. The EPA took this feedback into account in the development of this proposal.

The EPA's examination of potential EJ concerns in this proposed rule includes a proximity demographic analysis for 130 existing facilities that are currently subject to NSPS subpart KKKK. This represents facilities that might modify or reconstruct in the future and become subject to the proposed requirements in new subpart KKKKa. The locations of newly constructed sources that will become subject to subpart KKKKa are not known, thus, we are limited in our ability to estimate the potential EJ impacts of this rulemaking. As discussed in detail in section IV.F of this preamble, the results of the proximity demographic analysis indicate that the percent of population that is Black, Hispanic/Latino, or Asian living within 50 kilometers (km) of existing facilities with stationary combustion turbines is above the national average. In addition, the percent of population living within 50 km of existing facilities with stationary combustion turbines is also above the national average for linguistic isolation and people with one or more disabilities. Furthermore, within 5 km of the existing facilities with stationary combustion turbines, the percent of population is above the national average for people living below the poverty level and people living below two times the poverty level.

However, for the areas located downwind of any stationary combustion turbines that may be covered by new subpart KKKKa, we anticipate the proposed changes to the NSPS will generally reduce the potential emission impacts, in particular NO_X emissions. Specifically, for most subcategories of new, modified, and reconstructed stationary combustion turbines, the EPA is proposing combustion controls with SCR as the BSER and, accordingly, is proposing more protective NO_X standards of performance for affected sources based on the application of SCR post-combustion control technology and updated information on combustion control efficacy. Although this proposed rule does not preclude the construction of new combustion turbines, and emissions may increase as a result of increased operation of newly-constructed capacity, this proposed rule, if finalized, would ensure that any additional NO_X emissions from certain affected sources are reduced to a level consistent with the application of state-of-the-art control technology. Any source that commences construction, modification, or reconstruction after the date of publication of this proposal will be subject to the standards of performance that are ultimately finalized. Further, frontline communities have consistently raised concerns about increases in NO_X emissions from newly constructed stationary combustion turbines that plan to co-fire with hydrogen.[11] This proposed rule, when finalized, will help address those concerns by establishing more protective NO_X standards for stationary combustion turbines that plan to co-fire hydrogen.

Additionally, sources that install stationary combustion turbines that meet the applicability of NSPS subpart KKKKa will likely be subject to the New Source Review (NSR) preconstruction permitting program and, more specifically, the requirements of the ''major NSR'' program. Major NSR permitting requirements can offer protections for communities that are near sources that will experience an increase in NO_X and other emissions resulting from the installation and operation of new, modified, or reconstructed stationary combustion turbines. Under the major NSR program, the permitting requirements that apply to a source depend on the air quality designation at the location of the source for each of its emitted pollutants at the time the permit is issued. Major NSR permits for sources located in an area that is designated as attainment or unclassifiable for the National Ambient Air Quality Standards (NAAQS) for its pollutants are referred to as Prevention of Significant Deterioration (PSD) permits. Sources subject to PSD must, among other requirements, comply with emission limitations that reflect the Best Available Control Technology (BACT) for ''each pollutant subject to regulation'' [12] as specified by CAA

[10] *See* 89 FR 39798; May 9, 2024.

[11] See, for example, Docket ID No. EPA–HQ–OAR–2023–0072–0470, Docket ID No. EPA–HQ–OAR–2023–0072–0527, Docket ID No. EPA–HQ–OAR–2023–0072–0658, Docket ID No. EPA–HQ–OAR–2024–0135–0080, and Docket ID No. EPA–HQ–OAR–2024–0135–0114.

[12] For the PSD program, ''regulated NSR pollutant'' includes any criteria air pollutant and any other air pollutant that meets the requirements

Continued

sections 165(a)(4) and 169(3) and demonstrate through dispersion modeling techniques that the emissions from the project will not cause or contribute to a violation of the NAAQS or ''PSD increments.'' [13] Sources can often make this air quality demonstration based on the BACT level of control or, in some cases, may need to accept more stringent air quality-based limitations to model compliance with the ambient standards. Major NSR permits for sources located in nonattainment areas and that emit at or above the specified major NSR threshold for the pollutant for which the area is designated as nonattainment are referred to as Nonattainment NSR (NNSR) permits. Sources subject to NNSR must, among other requirements, meet the Lowest Achievable Emission Rate (LAER) pursuant to CAA sections 171(3) and 173(a)(2) for any pollutant subject to NNSR and must obtain emission ''offsets'' (*i.e.,* creditable decreases in emissions) from other sources in the area to compensate for the expected emission increases caused by the new source or modification. These required elements of PSD and NNSR permits can serve to further reduce potential emission impacts from stationary combustion turbines beyond the levels that would be required by the proposed changes to NSPS subpart KKKKa.

With respect to consideration of specific EJ concerns within the NSR permitting procedures, when the EPA is the issuing authority for the major NSR permit, it has legal authority to consider potential disproportionate environmental burdens on a case-by-case basis, taking into account case-specific factors germane to any individual permit decision. Although the minimum requirements for an approvable State NSR permitting program do not require the permitting authorities to reflect EJ considerations in their permitting decisions, States that implement NSR programs under an EPA-approved State implementation plan (SIP) have discretion to consider EJ in their NSR permitting actions and adopt additional requirements in the permitting decision to address potential disproportionate environmental burdens. Also, the NSR permit review process provides the discretion for permitting authorities to provide enhanced engagement for communities with EJ concerns. This includes opportunities to enhance EJ by facilitating increased public participation in the formal permit consideration process (*e.g.,* by granting requests to extend public comment periods, holding multiple public meetings, or providing translation services at hearings in areas with limited English proficiency) and taking informal steps to enhance participation earlier in the process, such as inviting community groups to meet with the permitting authority and express their concerns before a draft permit is developed.

G. How does the EPA perform the NSPS review?

As noted in section II of this preamble, CAA section 111 requires the EPA to, at least every 8 years, review and, if appropriate, revise the standards of performance applicable to new, modified, and reconstructed sources. If the EPA revises the standards of performance, those standards must reflect the degree of emission limitation achievable through the application of the BSER considering the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirements. CAA section 111(a)(1).

Section 111 of the CAA requires the EPA to consider a number of factors, including cost, in determining ''the best system of emission reduction . . . adequately demonstrated.'' CAA section 111(a)(1). The D.C. Circuit has long recognized that ''[CAA] section 111 does not set forth the weight that [ ] should [be] assigned to each of these factors;'' therefore, ''[the court has] granted the agency a great degree of discretion in balancing them.'' *Lignite Energy Council* v. *EPA,* 198 F.3d 930, 933 (D.C. Cir. 1999).

In reviewing an NSPS to determine whether it is ''appropriate'' to revise the standards of performance, the EPA evaluates the statutory factors identified in the paragraphs above, which may include consideration of the following information:

- Expected growth for the source category, including how many new facilities, reconstructions, and modifications may trigger NSPS in the future.
- Pollution control measures, including advances in control technologies, process operations, design or efficiency improvements, or other systems of emission reduction, that are ''adequately demonstrated'' in the regulated industry.
- Available information from the implementation and enforcement of current requirements indicating that emission limitations and percent reductions beyond those required by the current standards are achieved in practice.
- Costs (including capital and annual costs) associated with implementation of the available pollution control measures.
- The amount of emission reductions achievable through application of such pollution control measures.
- Any non-air quality health and environmental impact and energy requirements associated with those control measures.

The courts have recognized that the EPA has ''considerable discretion under [CAA] section 111,'' *id.,* on how it considers cost under CAA section 111(a)(1). In evaluating whether the cost of a particular system of emission reduction is reasonable, the EPA considers various costs associated with the particular air pollution control measure or a level of control, including capital costs and operating costs, and the emission reductions that the control measure or particular level of control can achieve. The Agency considers these costs in the context of the industry's overall capital expenditures and revenues. The Agency also considers cost effectiveness analysis as a useful metric and a means of evaluating whether a given control achieves emission reduction at a reasonable cost. A cost effectiveness analysis allows comparisons of relative costs and outcomes (effects) of two or more options. In general, cost effectiveness is a measure of the outcomes produced by resources spent. In the context of air pollution control options, cost effectiveness typically refers to the annualized cost of implementing an air pollution control option divided by the amount of pollutant reductions realized annually. Notably, a cost effectiveness analysis is not intended to constitute or approximate a benefit-cost analysis in which monetized benefits are compared to costs, but rather is intended to provide a metric to compare the relative cost of emissions reductions.

The statute does not identify a specific way in which the EPA is to assess cost, and the Agency does not apply a brightline test in determining what level of cost is reasonable. Rather, in evaluating whether the cost of a control is reasonable, the EPA typically has considered cost effectiveness along with various associated cost metrics, such as capital costs and operating costs, total costs, costs as a percentage

of 40 CFR 52.21(b)(50). Some of these non-criteria pollutants include greenhouse gases, fluorides, sulfuric acid mist, hydrogen sulfide, and total reduced sulfur.

[13] PSD increments are margins of ''significant'' air quality deterioration above a baseline concentration that establish an air quality ceiling, typically below the NAAQS, for each PSD area.

of capital for a new facility, and the cost per unit of production. In addition, other factors identified in CAA section 111(a) may bear on the EPA's evaluation of cost. For instance, if there is evidence of use of a technology across many of the recently constructed sources in a particular category, such evidence would provide a powerful indication that the cost of that technology is reasonable, or at a minimum, is not excessive. *See, e.g.,* 89 FR 16820, 16864–65; March 8, 2024.

After the EPA evaluates the statutory factors, the EPA compares the various systems of emission reductions and determines which system is ''best'' and therefore represents the BSER. The EPA then establishes a standard of performance that reflects the degree of emission limitation achievable through the implementation of the BSER. In performing this analysis, the EPA can determine whether subcategorization is appropriate based on classes, types, and sizes of sources and may identify a different BSER and establish different performance standards for each subcategory. The result of the analysis and BSER determination leads to standards of performance that apply to facilities that begin construction, modification, or reconstruction after the date of publication of the proposed standards in the **Federal Register**. Because the NSPS reflect the BSER under conditions of proper operation and maintenance, in doing its review, the EPA also evaluates and determines the proper testing, monitoring, recordkeeping, and reporting requirements needed to ensure compliance with the emission standards.

H. 2012 NSPS Proposal

On September 5, 2006, a petition for reconsideration of the revised NSPS was filed by the Utility Air Regulatory Group (UARG). The EPA granted reconsideration of subpart KKKK, and, on August 29, 2012, proposed to amend subpart KKKK as well as the original NSPS, subpart GG of 40 CFR part 60. *See* 77 FR 52554 (2012 NSPS Proposal). The proposed rulemaking addressed specific issues identified by the petitioners as well as other technical and editorial issues.

Specifically, the EPA proposed to clarify the intent in applying and implementing specific rule requirements, to correct unintentional technical omissions and editorial errors, and address various other issues that were identified since promulgation of subpart KKKK. The EPA has not taken further action on this proposed rule, and, in this action, proposes in the following section to include applicable clarifications and technical corrections in new subpart KKKKa.

III. What actions are we proposing?

A. Applicability

The source category that is the subject of this proposed action is composed of new stationary combustion turbines with a base load rating (maximum heat input of the combustion turbine engine at ISO conditions) of greater than 10 MMBtu/h of heat input.[14] The standards of performance, proposed to be codified in 40 CFR part 60, subpart KKKKa, once promulgated, would be directly applicable to affected sources that begin construction, modification, or reconstruction after the date of publication of the proposed standards in the **Federal Register**. The applicability of sources that would be subject to proposed subpart KKKKa is similar to that for sources subject to existing 40 CFR part 60, subpart KKKK. The proposed amendments to subparts GG and KKKK, once promulgated, would be directly applicable to the affected facilities already subject to those subparts. Stationary combustion turbines subject to the proposed standards in new subpart KKKKa would not be subject to the requirements of subparts GG or KKKK. The HRSG and duct burners subject to the proposed standards in subpart KKKKa would be exempt from the requirements of 40 CFR part 60, subpart Da (the Utility Boiler NSPS) as well as subparts Db and Dc (the Industrial/Commercial/Institutional Boiler NSPS), continuing the approach previously established in subpart KKKK.

Proposed subpart KKKKa maintains the NO_X exemptions promulgated previously in subparts GG and KKKK. In 1977, in subpart GG, the EPA determined that it was appropriate to exempt emergency combustion turbines from the NO_X limits. These included emergency-standby combustion turbines, military combustion turbines, and firefighting combustion turbines. Subpart KKKK further defines emergency combustion turbines as units that operate in emergency situations, such as turbines that supply electric power when the local utility service is interrupted. Additional exemptions in subpart KKKK include (1) stationary combustion turbine test cells/stands, (2) integrated gasification combined cycle (IGCC) combustion turbine facilities covered by subpart Da of 40 CFR part 60 (the Utility Boiler NSPS), and (3) stationary combustion turbines that, as determined by the Administrator or delegated authority, are used exclusively for the research and development of control techniques and/or efficiency improvements relevant to stationary combustion turbine emissions.

[14] The EPA uses the higher heating value (HHV) when specifying heat input ratings.

1. Revisions to 40 CFR Part 60, Subpart GG and 40 CFR Part 60, Subpart KKKK That Would Also Be Included in 40 CFR Part 60, Subpart KKKKa

The EPA is proposing to make two revisions to subparts GG and KKKK that also are proposed to be included in a new subpart KKKKa. Therefore, revised subparts GG and KKKK use similar regulatory text as subpart KKKKa except where specifically stated. This section describes provisions that would be included in all three subparts. The proposed amendments also include updating 40 CFR 60.17 (incorporations by reference) to include additional test methods identified in subpart KKKKa and revising the wording and writing style to clarify the requirements of the NSPS. The Agency does not intend for these editorial revisions to substantively change any of the technical requirements of the existing subparts GG and KKKK. To the extent that the EPA determines that the revisions do have unintended substantive effects, corrections will be made in the final action on the proposed rule.

a. Exemptions for Combustion Turbines Subject to More Stringent Standards

The EPA is proposing that stationary combustion turbines at petroleum refineries subject to subparts J or Ja of 40 CFR part 60 are not subject to the SO_2 performance standards in subparts GG, KKKK, or those proposed in new subpart KKKKa. The SO_2 standards in subparts J and Ja are more stringent than the SO_2 limits currently in subparts GG, KKKK, or proposed to be included in new subpart KKKKa. This proposed action would simplify compliance for owners or operators of petroleum refineries without an increase in pollutant emissions. The EPA is soliciting comment on whether there are additional source categories of facilities with stationary combustion turbines that are subject to more stringent NSPS that should not be subject to the SO_2 and/or NO_X standards in subparts GG, KKKK, or those proposed to be included in new subpart KKKKa.

b. Owners/Operators of Combustion Turbines Subject to 40 CFR Part 60, Subpart GG or 40 CFR Part 60, Subpart KKKK Can Petition To Comply With 40 CFR Part 60, Subpart KKKKa

The EPA is proposing to allow owners or operators of stationary combustion turbines currently covered by subparts GG or KKKK, and any associated steam generating unit subject to an NSPS, to have the option to petition the Administrator to comply with subpart KKKKa in lieu of complying with subparts GG, KKKK, and any associated steam generating unit NSPS. Since the applicability of subpart KKKKa encompasses any associated heat recovery equipment, owners or operators would have the flexibility to comply with one NSPS instead of multiple NSPS. The Administrator will only grant the petition if they determine that compliance with subpart KKKKa would be equivalent to, or more stringent than, compliance with subparts GG, KKKK, or any associated steam generating unit NSPS.

Also, the EPA is clarifying that if any solid fuel as defined in new proposed subpart KKKKa is burned in the HRSG, the HRSG would be covered by the applicable steam generating unit NSPS and not subpart KKKKa. The EPA is not aware of any existing stationary combustion turbines subject to subparts GG or KKKK that burn solid fuel in the HRSG, but the intent of this amendment is to cover only liquid and gaseous fuels. The amendment would prevent a large solid fuel-fired boiler from using the exhaust from a combustion turbine engine to avoid the requirements of the applicable steam generating unit NSPS.

2. Applicability of 40 CFR Part 60, Subpart KKKKa That Is Different From the Applicability of 40 CFR Part 60, Subpart KKKK

This section describes applicability provisions proposed in new subpart KKKKa that are different from the applicability provisions in existing subpart KKKK.

a. Clarification to Definition of Stationary Combustion Turbine

The combustion turbine engine (*i.e.,* the air compressor, combustor, and turbine sections) is the primary source of emissions from a stationary combustion turbine. In subpart KKKK, the definition of the affected source includes the HRSG and associated duct burners at combined cycle and CHP facilities. *See* 71 FR 38483; July 6, 2006. This means that the replacement of only the combustion turbine portion of a combined cycle or CHP facility may not constitute a new affected facility. This also means the cost to replace only the combustion turbine engine portion at an existing combined cycle or CHP facility may not constitute most of the costs compared to the replacement of the combustion turbine engine portion *and* the HRSG portion. This, in turn, is relevant to determining whether an affected source has ''reconstructed'' because, in general, a reconstructed facility is one that has had components replaced to the extent that the fixed capital costs of the new components exceed 50 percent of the fixed capital costs that would be required to construct a comparable entirely new facility. *See* 40 CFR 60.15. When the definition of an affected facility was expanded in subpart KKKK, it was not the intent of the EPA to change the determination of whether an existing combustion turbine is ''new'' or ''reconstructed.'' The EPA is proposing that it is appropriate that owners or operators of combined cycle and CHP facilities that entirely replace or undertake major capital investments in the combustion turbine engine portion of the facility invest in emissions control equipment as well.

In new subpart KKKKa, the EPA is proposing to maintain the definition of the affected source that was promulgated in subpart KKKK. However, to clarify the applicability of this definition when determining whether an existing combustion turbine engine should be considered to be ''new'' or ''reconstructed,'' the EPA is proposing to amend the rule language in new subpart KKKKa. The new language would clarify that the test for determining if an affected facility is a new source would be based on whether the combustion turbine portion of the affected facility is entirely replaced. The reconstruction applicability determination would be based on whether the fixed capital costs of the replacement of components of the combustion turbine engine portion exceed 50 percent of the fixed capital costs that would be required to install *only* a comparable new combustion turbine engine portion of the affected facility. The purpose of the 50 percent cost threshold is to ensure that sources that undertake sufficiently large capital investments as to effectively be ''new'' sources are required to invest in emissions controls as well, and do not avoid performance standards that would otherwise apply to new sources. In the case of a stationary combustion turbine, which is the regulated source for this source category, a capital investment that amounts to 50 percent of the replacement cost of the combustion turbine engine portion itself is sufficiently major as to make it appropriate to require the owner or operator to invest in emissions controls to meet the requirements in subpart KKKKa. This approach would not consider the costs to replace the HRSG (or its components) when only components of the combustion turbine engine portion are being replaced.

This approach to applying the definition of a reconstructed source would ensure that if an existing combined cycle or CHP facility replaces only the combustion turbine engine portion (or its components), then only the replaced portion (*i.e.,* the combustor) would be considered in a cost analysis to determine whether the source is reconstructed and thus subject to the NSPS performance standards in subpart KKKKa. For example, if a combined cycle turbine engine is replaced at an existing facility subject to subpart KKKK while the HRSG (or its components) is not replaced, then the cost to replace only the combined cycle turbine engine portion would be considered in the applicability determination. If the new turbine engine is determined to be a reconstructed source, then it would be subject to the proposed performance standards for reconstructed combustion turbines in subpart KKKKa. The HRSG at this hypothetical facility would also become subject to subpart KKKKa. It would make no practical difference for a HRSG to remain subject to subpart KKKK while the turbine becomes subject to subpart KKKKa, because the EPA is proposing to maintain the same treatment of the HRSG as in subpart KKKK.

In addition, compliance with subpart KKKKa would be minimally impacted by any potential reconstruction of the HRSG. Since the proposed standards in subpart KKKKa are input-based, with optional alternative output-based standards, the efficiency of the HRSG is not essential for demonstrating compliance. Further, the presence of duct burners should not significantly impact the emissions rate since low NO_X natural gas-fired duct burners typically contribute 15 ppm to 25 ppm NO_X corrected to 15 percent O_2, and ultra-low NO_X duct burners are available that contribute approximately 3 ppm NO_X corrected to 15 percent O_2. Under this approach, the replacement or addition of a new combustion turbine engine to a facility while retaining the existing HRSG would be considered a reconstruction, resulting in the applicability of subpart KKKKa. Likewise, the replacement or addition of a HRSG associated with a combustion turbine engine covered by subparts KKKK or GG would not result in the entire facility being subject to subpart KKKKa. Nonetheless, the Agency emphasizes that this treatment only concerns the meaning of ''new'' and ''reconstruction'' for purposes of subpart KKKKa; existing facilities making physical or operational changes must separately evaluate whether those changes constitute ''modification'' under 40 CFR 60.14 and thereby become subject to subpart KKKKa as a modified source.[15] See sections III.B.4 of this preamble for discussion of the EPA's proposed approach for subcategorization and section III.B.12 for discussion of the proposed emission standards in subpart KKKKa.

B. NO_X Emission Standards

1. Overview

This section discusses and proposes requirements for stationary combustion turbines that commence construction, modification, or reconstruction after December 13, 2024. The EPA is proposing that these requirements will be codified in 40 CFR part 60, subpart KKKKa. The EPA explains in section III.B.2 how NO_X formation occurs when fuel is burned in a stationary combustion turbine. Section III.B.3 discusses the subcategories the EPA promulgated in subpart KKKK as compared to the subcategory approach being proposed in new subpart KKKKa. Notably, in section III.B.4, the EPA is proposing size-based subcategories that reflect our consideration of the performance of different combustion turbine designs and current NO_X control technologies. The proposed BSER for control of NO_X emissions for each proposed subcategory of combustion turbines is discussed in sections III.B.7 through III.B.11, and the application of a particular BSER corresponds to the NO_X performance standards proposed in section III.B.12. The EPA's determination of the subcategories, BSER, and NO_X standards in this action considers multiple factors. These include whether the size of a new, modified, or reconstructed stationary combustion turbine is small, medium, or large (*i.e.,* base load); whether the affected source would operate at high or low hourly duty cycles; whether the affected source would operate at low, intermediate, or high annual capacity factors; and whether the affected source would burn natural gas, non-natural gas (such as distillate fuels), hydrogen, or a combination of the three.

As mentioned previously, in section III.B.7, the EPA describes the NO_X emission control technologies it evaluated as part of its review of the NSPS. These include dry combustion controls (*e.g.,* lean premix/dry low NO_X (DLN) systems), wet combustion controls (*e.g.,* water or steam injection), and post-combustion selective catalytic reduction (SCR). This is followed by a discussion of the EPA's proposed determination of the BSER for each of the subcategories of combustion turbines.

To summarize the EPA's proposed BSER determinations for NO_X: In general, the EPA is proposing that combustion controls with the addition of post-combustion SCR is the BSER for combustion turbines in the small, medium, and large subcategories. Since subpart KKKK was promulgated in 2006, it has become clear that SCR technology is a widely available and frequently adopted NO_X emissions control strategy for a wide range of sizes and types of combustion turbines. In general, and as described in more detail in the sections that follow, the EPA finds that SCR is adequately demonstrated for this source category, is generally cost-effective, and satisfies the other statutory criteria under CAA section 111(a)(1). However, the Agency also recognizes that as the size of a combustion turbine diminishes and/or as the level of operation of a combustion turbine diminishes or becomes more variable, the cost-effectiveness on a per-ton basis and efficacy of SCR technology also diminishes.

Thus, at smaller sizes and at lower operating levels, the EPA proposes to establish standards that are based on the use of combustion controls without SCR. Specifically, for small combustion turbines (*i.e.,* those that have a base load heat input rating of less than or equal to 250 MMBtu/h) that operate at an annual capacity factor[16] less than or equal to 40 percent (*i.e.,* low and intermediate load combustion turbines), the EPA is proposing that the use of combustion controls alone remains the BSER. For medium combustion turbines (*i.e.,* those that have a base load heat input rating of greater than 250 MMBtu/h but less than or equal to 850 MMBtu/h) that operate at capacity factors less than or equal to 20 percent (*i.e.,* low load combustion turbines), the EPA is proposing that combustion controls alone remain the BSER. Likewise, for large combustion turbines (*i.e.,* those that have a base load heat input rating of greater than 850 MMBtu/h) that operate at capacity factors less than or equal to 20 percent (*i.e.,* low load combustion turbines), the EPA is proposing that the use of combustion controls alone remains the BSER.

As discussed in further detail in the sections that follow, the EPA is requesting comment on several alternative approaches to determining the BSER and appropriate NO_X emission standards, particularly for small combustion turbines (*i.e.,* those that have a base load heat input rating of less than or equal to 250 MMBtu/h). Also, the EPA is taking comment on different ways of defining the size and capacity factor thresholds for establishing the subcategories described in this proposal.

In section III.B.13, the EPA explains the proposed BSER and NO_X emission standards for modified sources. The EPA is proposing in new subpart KKKKa that the BSER and NO_X emission standards for modified stationary combustion turbines are the same as those for certain corresponding new and reconstructed subcategories. For other subcategories, the proposed BSER and NO_X emission stanards for modified sources are different. Furthermore, in section III.B.14, the EPA explains its proposed approach to characterize new, modified, and reconstructed stationary combustion turbines that elect to co-fire with a percentage blend of hydrogen (by volume) as either natural gas-fired or non-natural gas-fired sources. Depending on whether the combustion turbine co-fires more or less than 30 percent hydrogen (by volume), it is proposed to be subject to the same BSER and NO_X performance standards applicable to either natural gas-fired or non-natural gas-fired combustion turbines in the same size-based subcategory. This section also includes a discussion of the technologies the EPA is proposing as BSER for each of the non-natural gas subcategories and the basis for proposing those controls, and not others, as the BSER.

2. NO_X Formation

Nitrogen oxides (NO_X) are a group of gases that are produced by stationary combustion turbines when fuel is

[15] The EPA proposed a similar approach to reconstruction for subpart KKKK in the 2012 NSPS Proposal. The Agency is not finalizing this change in subpart KKKK and is not altering the approach to reconstruction for purposes of determining the applicability of that subpart. Nonetheless, all existing sources that engage in reconstruction or modification after the date of this proposal would thereby become subject to subpart KKKKa and sources that meet the proposed new or reconstruction test under subpart KKKKa, if finalized, would be subject to subpart KKKKa and would no longer be subject to subpart KKKK.

[16] Capacity factor is a ratio that measures how often a stationary combustion turbine is operating at its maximum rated heat input. The ratio is based on heat input, or *actual* heat input, compared to the base load rating, or *potential* maximum heat input, under specified conditions.

burned at high temperatures. These gases are a mixture of nitric oxide (NO) and nitrogen dioxide (NO_2) and play a major role as precursor pollutants in atmospheric reactions with volatile organic compounds (VOC) that produce ozone (*i.e.,* smog), particularly on hot summer days. As a precursor pollutant, NO_X also reacts with water, oxygen, and other chemicals in the air to form particulate matter (PM) and contributes to acid deposition. NO_X is also a criteria pollutant for which there are National Ambient Air Quality Standards (NAAQS). The NAAQS for NO_X include a 1-hour standard at a level of 100 parts per billion (ppb) based on the 3-year average of the 98th percentile of the yearly distribution of 1-hour daily maximum concentrations, and an annual standard at a level of 53 ppb.[17] The direct health effects of NO_X are primarily respiratory effects, including irritation of the eyes, nose, throat, and lungs. Exposure to low levels of NO_X can lead to fluid build-up in the lungs. Inhalation of high levels of NO_X can lead to burning, spasms, and swelling of tissues in the throat and upper respiratory tract, reduced oxygenation of the body tissues, and build-up of fluid in the lungs, and death.[18] Elevated concentrations of NO_2 can exacerbate asthma in the short term and may contribute to asthma development in the long term. People with asthma, as well as children and the elderly, are generally at greater risk for the health effects of NO_2.[19]

In addition, environmental effects of NO_X pollution include adverse effects on foliage, and, via nitrogen deposition, effects on ecosystems, such as the acidification of aquatic and terrestrial ecosystems and nutrient enrichment.

Total NO_X emissions are a function of thermal and organic (*i.e.,* fuel) NO_X. Thermal NO_X is formed in a well-defined, high-temperature reaction between nitrogen and oxygen from the combustion air. Meanwhile, organic NO_X is formed from fuel-bound nitrogen that reacts with oxygen in the combustion chamber. Thermal NO_X accounts for the majority of NO_X emitted by stationary combustion turbines because natural gas typically does not have a high nitrogen composition.[20] As discussed in more detail below, dry and wet combustion controls reduce the peak flame temperatures, thus limiting NO_X emissions, while SCR technology catalytically promotes the conversion of NO_X to nitrogen gas (N_2) in the exhaust gases of stationary combustion turbines.

3. Subcategorization Approach and NO_X Emission Standards in 40 CFR Part 60, Subpart KKKK

In subpart KKKK, the EPA lists 14 subcategories of stationary combustion turbines and identifies NO_X standards for affected sources in each subcategory based on the application of dry or wet NO_X combustion controls. The size-based subcategories include combustion turbines with base load ratings of less than or equal to 50 MMBtu/h of heat input, those with base load ratings greater than 50 MMBtu/h of heat input and less than or equal to 850 MMBtu/h, and those with base load ratings greater than 850 MMBtu/h of heat input. These subcategories are based on the rating of the turbine engine, do not include any supplemental fuel input to the heat recovery system, and are consistent with combustion control technologies (and manufacturer guarantees) available at the time that subpart KKKK was promulgated for different size combustion turbines. Within each size-based subcategory there are individual NO_X standards based on whether the combustion turbine is burning natural gas or non-natural gas fuels and reflect the availability of wet or dry low NO_X combustion controls for different fuels.

There are also separate subcategories in subpart KKKK for modified and reconstructed stationary combustion turbines (reflecting more limited availability of combustion controls); heat recovery units operating independent of the combustion turbine (reflecting the emissions rate of a boiler); combustion turbines operating at part load or operating at low ambient temperatures (or north of the Arctic Circle); and offshore turbines (reflecting the ability of combustion controls to operate under these conditions). *See* Table 1: NO_X Emission Standards (71 FR 38483; July 6, 2006). The NO_X standards within these 14 subcategories in subpart KKKK are as low as 15 ppm for combustion turbines firing natural gas with a design heat input rating of greater than 850 MMBtu/h and as high as 150 ppm for sources firing non-natural gas fuels with a design heat input rating of less than or equal to 50 MMBtu/h.

4. Proposed Subcategorization Approach in 40 CFR Part 60, Subpart KKKKa

The EPA is proposing three size-based subcategories in subpart KKKKa for stationary combustion turbines that commence construction, modification, or reconstruction after December 13, 2024. The proposed subcategories include combustion turbines with base load ratings of less than or equal to 250 MMBtu/h of heat input, those with base load ratings of greater than 250 MMBtu/h of heat input and less than or equal to 850 MMBtu/h, and those with base load ratings greater than 850 MMBtu/h of heat input.[21] Like subpart KKKK, these subcategories are based on the rating of the turbine engine and do not include any supplemental fuel input to the heat recovery system and are consistent with combustion control technologies (and manufacturer guarantees) currently available for different sized combustion turbines.

For the purposes of subpart KKKKa, the EPA refers to stationary combustion turbines as small (base load ratings of less than or equal to 250 MMBtu/h of heat input), medium (base load ratings of greater than 250 MMBtu/h of heat input and less than or equal to 850 MMBtu/h), and large (base load ratings of greater 850 MMBtu/h of heat input), respectively. In addition, the EPA is proposing to further subcategorize small, medium, and large combustion turbines as low load, intermediate load, or base load units depending on 12-calendar-month capacity factors. Low load combustion turbines would be those with a 12-calendar-month capacity factor of less than or equal to 20 percent. Intermediate load combustion turbines would be those with a 12-calendar-month capacity factor of greater than 20 percent but less than or equal to 40 percent. Base load combustion turbines would be those with a 12-calendar-month capacity factor greater than 40 percent. For each of these proposed subcategories, the EPA proposes to carry forward to new subpart KKKKa the current subpart KKKK approach to subcategorize stationary combustion turbines further depending on whether they are natural

[17] U.S. Environmental Protection Agency (EPA). Nitrogen Dioxide (NO_2) Pollution. Available at *https://www.epa.gov/no2-pollution/primary-national-ambient-air-quality-standards-naaqs-nitrogen-dioxide.*

[18] Agency for Toxic Substances and Disease Registry (ATSDR). (March 25, 2014). *ToxFAQs for Nitrogen Oxides.* Toxic Substances Portal fact sheet. Available at *https://wwwn.cdc.gov/TSP/ToxFAQs/ToxFAQsDetails.aspx?faqid=396&toxid=69.*

[19] U.S. Environmental Protection Agency (EPA). Nitrogen Dioxide (NO_2) Pollution. Available at *https://www.epa.gov/no2-pollution/basic-information-about-no2#Effects.*

[20] Our BSER analysis focuses on traditional turbines where the fuel is combusted in air. There is at least one vendor developing new turbines where the fuel is combusted in pure oxygen. In that case, there would be no thermal NO_X formed in the combustion process.

[21] The EPA is proposing the same BSER regardless of the end use of the combustion turbine—direct mechanical and electric generating applications would be subject to the same emission standards.

gas-fired or non-natural gas-fired. In addition, the EPA proposes to carry forward to new subpart KKKKa the current subpart KKKK subcategorization for combustion turbines operating at part loads, combustion turbines located north of the Arctic Circle, combustion turbines operating at ambient temperatures of less than 0 °F,[22] and HRSG units operating independent of the combustion turbine.

a. Size-Based Subcategories

This section discusses the EPA's proposals to create size-based subcategories for new, modified, and reconstructed stationary combustion turbines in new subpart KKKKa that are different from the size-based subcategory approach established in existing subpart KKKK. Specifically, the EPA is proposing size-based subcategories for combustion turbines that have base load ratings less than or equal to 250 MMBtu/h of heat input, base load ratings greater than 250 MMBtu/h of heat input and less than or equal to 850 MMBtu/h, and base load ratings greater than 850 MMBtu/h of heat input. The EPA also is proposing to divide these subcategories of combustion turbines further based on their utilization (*i.e.,* 12-calendar-month capacity factor), depending on whether they operate as low, intermediate, or base load units. The proposed BSER and applicable NO_X emission standards would depend on the size of the stationary combustion turbine as determined by its base load rated heat input and on how it is utilized based on its 12-calendar-month capacity factor.

The proposed subcategories in subpart KKKKa are based in part on the availability and performance of NO_X combustion controls for different designs and sizes of stationary combustion turbines. These factors were also key to determining the size-based subcategories in current subpart KKKK. For example, as discussed previously, subpart KKKK includes a subcategory for combustion turbines with a base load rated heat input of less than or equal to 50 MMBtu/h, and this subcategory was determined to be appropriate because the EPA had found that combustion controls for these size combustion turbines have limited availability relative to larger combustion turbines. Therefore, the EPA further divided this subcategory into electric generating and mechanical drive applications and determined the BSER for electric applications to be water injection and the BSER for mechanical drive applications to be available combustion controls.

For combustion turbines in the subcategory of sources with greater than 50 MMBtu/h of heat input and less than or equal to 850 MMBtu/h of heat input, the BSER in subpart KKKK is combustion controls available for aeroderivative combustion turbines, because, when subpart KKKK was proposed in 2005, the largest aeroderivative combustion turbines were less than 850 MMBtu/h.

For the subcategory of combustion turbines that are greater than 850 MMBtu/h of heat input, the BSER in subpart KKKK is combustion controls available for frame combustion turbines. The EPA had determined that frame combustion turbines are generally physically larger per amount of output than aeroderivative combustion turbines, given larger areas to stage combustion that results in lower NO_X emissions.

b. Combustion Turbines Less Than or Equal to 250 MMBtu/h

The EPA is proposing in subpart KKKKa to create a subcategory for all new and reconstructed stationary combustion turbines with base load ratings of less than or equal to 250 MMBtu/h of heat input (*i.e.,* small turbines). The EPA is proposing this size-based subcategory for small stationary combustion turbines based, in part, on a review of available combustion controls and manufacturer guarantees for NO_X emissions from these smaller turbine designs. The results of this technology review demonstrate that multiple manufacturers have developed dry combustion controls that can achieve NO_X emission rates comparable to the NO_X emission rates achieved by larger models of combustion turbines for both electrical and mechanical applications. This subcategory of small combustion turbines with base load ratings of less than or equal to 250 MMBtu/h of heat input also is proposed to be appropriate because it supports consistency across multiple rulemakings and approximately corresponds to the 25 MW threshold for a combustion turbine to be considered an electric generating unit (EGU) in the recently promulgated NSPS for greenhouse gas (GHG) emissions (*i.e.,* the Carbon Pollution Standards).[23] *See* 89 FR 39798; May 9, 2024.

In new subpart KKKKa, different from the existing subcategories in subpart KKKK, the EPA is not proposing a subcategory for stationary combustion turbines with base load ratings of less than or equal to 50 MMBtu/h of heat input. The EPA proposes to determine that this subcategory is no longer necessary since multiple manufacturers have developed effective dry combustion controls for nearly all new turbines smaller than 50 MMBtu/h of heat input, and these dry combustion controls are capable of limiting NO_X emissions to the same rates as those achieved by larger combustion turbines for both electrical and mechanical applications. According to the subcategory approach proposed in subpart KKKKa, any new or reconstructed stationary combustion turbine with a base load rating of less than or equal to 50 MMBtu/h of heat input would be included in the subcategory of combustion turbines with base load ratings of less than or equal to 250 MMBtu/h of heat input and subject to the same NO_X performance standards. Also, the EPA is proposing in new subpart KKKKa that electrical and mechanical applications can apply identical combustion controls and that separate subcategories for these sources are no longer necessary.

The EPA also is proposing in new subpart KKKKa to further subcategorize stationary combustion turbines with base load ratings of less than or equal to 250 MMBtu/h of heat input according to capacity factors. Small low load stationary combustion turbines would be those with 12-calendar-month capacity factors of less than or equal to 20 percent, small intermediate load stationary combustion turbines would be those with 12-calendar-month capacity factors greater than 20 percent and less than or equal to 40 percent, and small base load stationary combustion turbines would be those with 12-calendar-month capacity factors greater than 40 percent.

According to this subcategorization approach, the EPA is proposing in new subpart KKKKa that all new and reconstructed stationary combustion turbines with base load ratings of less than or equal to 250 MMBtu/h of heat input and that are utilized as low or intermediate load units (*i.e.,* with 12-calendar-month capacity factors less than or equal to 40 percent) would have a BSER of combustion controls. Furthermore, as discussed in section III.B.12, the EPA is proposing that these small low and intermediate load combustion turbines would be subject to a NO_X performance standard based upon application of the proposed BSER

[22] If any of these conditions are applicable, the combustion turbine would be in this subcategory.

[23] EGUs are subject to different regulatory criteria outside of the NSPS as compared to small industrial combustion turbines (*e.g.,* greenhouse gas standards of performance). These other regulatory criteria can be accounted for in the baseline levels of control the EPA uses when evaluating the BSER.

and whether they burn natural gas or non-natural gas fuels.

The EPA also is proposing in subpart KKKKa that all new and reconstructed stationary combustion turbines with base load ratings of less than or equal to 250 MMBtu/h of heat input that are utilized as base load units (*i.e.,* with 12-calendar-month capacity factors greater than 40 percent) would have a BSER of combustion controls plus additional post-combustion SCR technology. The EPA proposes in section III.B.12 that these small base load stationary combustion turbines would be subject to a NO_X performance standard based upon application of the proposed BSER and whether they burn natural gas or non-natural gas fuels.

As for modified stationary combustion turbines with base load ratings of less than or equal to 250 MMBtu/h of heat input, the EPA is proposing in subpart KKKKa that the BSER is combustion controls—regardless of 12-calendar-month capacity factor. All small modified stationary combustion turbines would be subject to a NO_X performance standard based application of the proposed BSER and whether they burn natural gas or non-natural gas fuels.

In this action, the EPA is soliciting comment on whether the base load rating of less than or equal to 250 MMBtu/h of heat input is an appropriate threshold to distinguish between small and medium stationary combustion turbines for purposes of determining the BSER and proposing NO_X standards in subpart KKKKa. For example, as discussed further in section III.B.9, if the EPA were to determine that SCR was not an appropriate BSER for all small stationary combustion turbines, then it may be appropriate to adjust the size-based thresholds such that turbines of greater than 50, 100, or 150 MMBtu/h of heat input should be treated as ''medium'' turbines.

c. Combustion Turbines Greater Than 250 MMBtu/h and Less Than or Equal to 850 MMBtu/h

The EPA is proposing to create a subcategory in new subpart KKKKa for new and reconstructed medium stationary combustion turbines, which would be turbines with base load ratings of greater than 250 MMBtu/h of heat input and less than or equal to 850 MMBtu/h. Furthermore, in subpart KKKKa, the EPA is proposing to divide this medium subcategory into low load (12-calendar-month capacity factors of less than or equal to 20 percent), intermediate load (12-calendar-month capacity factors greater than 20 percent and less than or equal to 40 percent), and base load (12-calendar-month capacity factors greater than 40 percent) with separate proposed BSER and NO_X emission standards, as discussed in sections III.B.10 and III.B.12.

The EPA also is soliciting comment on whether it is appropriate for medium stationary combustion turbines that are EGUs [24] to determine their utilization thresholds according to 12-operating-month electric sales instead of 12-calendar-month capacity factors. Some new and reconstructed stationary combustion turbines that would be subject to new subpart KKKKa also meet the applicability criteria in the Carbon Pollution Standards and are considered EGUs. Determining the utilization thresholds for combustion turbine EGUs based on 12-operating-month electric sales would better align this proposal with the subcategorization approach in the final Carbon Pollution Standards.

d. Combustion Turbines Greater Than 850 MMBtu/h

In new subpart KKKKa, the EPA is proposing to maintain the subcategory of large stationary combustion turbines with base load ratings of greater than 850 MMBtu/h of heat input, similar to the existing subcategory for large combustion turbines in subpart KKKK. However, the EPA is proposing in subpart KKKKa to further divide these combustion turbines into three subcategories based on the rolling 12-calendar-month utilization. As discussed for the small- and medium-sized combustion turbines, this proposed subcategorization is consistent with the Carbon Pollution Standards and includes subcategories for large combustion turbines with greater than 850 MMBtu/h of heat input that operate at low, intermediate, or base load capacity factors. In terms of capacity factors, the large low load stationary combustion turbines would be those with 12-calendar-month capacity factors of less than or equal to 20 percent, the large intermediate load stationary combustion turbines would be those with 12-calendar-month capacity factors greater than 20 percent and less than or equal to 40 percent, and the large base load stationary combustion turbines would be those with 12-calendar-month capacity factors greater than 40 percent.

The EPA also is soliciting comment on whether it is appropriate for large stationary combustion turbines that are EGUs to determine their utilization thresholds according to 12-operating-month electric sales instead of 12-calendar-month capacity factors. Some new and reconstructed large stationary combustion turbines that would be subject to new subpart KKKKa also meet the applicability criteria in the Carbon Pollution Standards and are considered EGUs. Determining the utilization thresholds for combustion turbine EGUs based on 12-operating-month electric sales would better align this proposal with the subcategorization approach in the final Carbon Pollution Standards.

e. Natural Gas and Non-Natural Gas Subcategories

In subpart KKKK, stationary combustion turbines are categorized as non-natural gas-fired sources when greater than 50 percent of the heat input is from a non-natural gas fuel during part of an hour of operation. The EPA is proposing to maintain that categorization in new subpart KKKKa.

In the 2012 NSPS Proposal discussed in section II.H, the EPA proposed to base the emissions standard only on the fuel burned in the combustion turbine engine (*i.e.,* any fuel combusted in the duct burners of the HRSG would not impact the applicable emissions rate) and to eliminate the 50 percent fuel requirement so that the non-natural gas emissions standard would apply when any amount of non-natural gas fuel is burned in the combustion turbine engine. This proposed change was intended to avoid creating a compliance issue when combustion turbines switch from utilizing gaseous fuels (that can utilize lean premix/DLN combustion) to liquid fuels (that utilize diffusion flame combustion).

As previously noted, the EPA took no further action on the 2012 NSPS Proposal. In this action, the EPA is soliciting comment on whether to adopt, in subpart KKKKa, the approach included in the 2012 NSPS Proposal. The EPA believes that this approach could provide a more accurate representation of the performance of applicable control technologies and is soliciting comment on the specifics of co-firing fuels in a combustion turbine engine and how combustion turbines switch fuels. Specifically, the EPA seeks comment on whether multiple fuels can be combusted simultaneously in a combustion turbine engine, which fuels can be combusted in combination, and under what conditions. The EPA also seeks comment on whether it is necessary for a combustion turbine to temporarily cease operation or reduce load to switch from natural gas to distillate oil, or can switch fuels while operating at high loads. Finally, if switching can be done at high loads, the

[24] EGU stationary combustion turbines are those that meet the applicability requirements of proposed subpart KKKKa and also the applicability requirements of subpart TTTTa as described in 40 CFR 60.5509a (*See* 89 FR 40036).

EPA seeks comment on at what point it is necessary to switch from lean premix/DLN combustion, which is only applicable to gaseous fuels, to diffusion flame combustion. Specifically, whether it is necessary to operate using diffusion flame combustion while utilizing natural gas prior to switching to fuel oil, and if this could create a compliance issue for hours during fuel switching. The EPA is soliciting comment on if this issue is technically accurate.

A potential issue with removing the 50 percent fuel requirement is that this treatment could create an incentive for an owner/operator to combust a small amount of non-natural gas fuel and thereby obtain a far less stringent emissions standard. Therefore, the EPA is soliciting comment on what mitigating provisions would be necessary to ensure that this treatment only operates in the narrow window where it might be appropriate for legitimate technical reasons. Specifically, if the EPA were to remove the 50 percent fuel requirement, the EPA also solicits comment on limiting the number of hours a combustion turbine may burn multiple fuel types, through longer averaging times for determining compliance, and/or through mass-based caps on the total emissions that are permitted during periods of fuel switching.

The EPA is proposing in new subpart KKKKa that the NO_X standards are based on the type of fuel being burned in the combustion turbine engine alone. Contrary to subpart KKKK, this would not account for the type of fuel being burned in duct burners associated with the HRSG. In subpart KKKK, the applicable NO_X standards are based on the total heat input to the stationary combustion turbine, including any associated duct burners. However, fuel choice impacts combustion turbine engine NO_X emissions to a greater degree than it impacts such emissions from a duct burner. Therefore, in subpart KKKKa, the Agency is proposing to include that the NO_X standard be based on the type of fuel being burned in the combustion turbine engine alone. The natural gas standard would apply at those times when the fuel input to the combustion turbine engine meets the definition of natural gas, regardless of the fuel, if any, that is burned in the duct burners.

The Agency is also proposing to add a provision allowing for a site-specific NO_X standard for an owner/operator of a stationary combustion turbine that burns by-product fuels. The owner/operator would be required to petition the Administrator for a site-specific standard using a procedure similar to what is currently required by subpart Db of 40 CFR part 60 (the Industrial Boiler NSPS). The Agency considers it appropriate to propose this provision because new subpart KKKKa covers the HRSG that was previously covered by subpart Db when the site-specific standard was adopted for industrial boilers. The Agency also solicits comment on whether to amend existing subpart KKKK to provide a provision allowing for a site-specific NO_X standard for an owner/operator of a stationary combustion turbine that burns by-product fuels.

f. Subcategory for Combustion Turbines Operating at Part Loads, Located North of The Arctic Circle, or Operating at Ambient Temperatures of Less Than 0 °F

When subpart GG (the original stationary gas turbine criteria pollutant NSPS) was promulgated in 1979, the NO_X emission standards and compliance were based on performance testing. Based on subsequent rulemakings, owners/operators of a gas turbine subject to subpart GG with a NO_X continuous emissions monitoring system (CEMS) began determining excess emissions on a 4-hour rolling average basis. The 4-hour basis was determined to be the approximate time required to conduct a performance test using the performance test method specified in subpart GG. This 4-hour rolling average became the default for determining the emission rates of gas turbines, and, in 2006, was used in the subsequent review of the stationary combustion turbine criteria pollutant NSPS (subpart KKKK).

When subpart KKKK was proposed in 2005, the NO_X performance emissions data were again based on stack performance tests, which are representative of emission rates at high hourly loads, rather than on CEMS data. The final NO_X standards for high hourly loads were consistent with the performance test data and manufacturer guarantees. Manufacturer guarantees are only applicable during specific conditions, which include the load of the combustion turbine and the ambient temperatures. When combustion turbines are operated at part loads and/or at low ambient temperatures, the identified BSER in subpart KKKK—low NO_X combustion controls—were not as effective at reducing NO_X from a technical standpoint.[25] At part-load operation and low ambient temperatures, it is more challenging to maintain stable combustion using dry low NO_X (DLN) and adjustments to the combustion system are required—resulting in higher NO_X emission rates. Therefore, in subpart KKKK, the Agency identified diffusion flame combustion as the BSER for hours of part-load operation or low ambient temperatures.[26]

In subpart KKKK, a part-load hour is defined as any hour when the heat input rate is less than 75 percent of the base load rating of the combustion turbine. If the heat input rate drops below 75 percent at any point during the hour, the entire hour is considered a part-load hour, and the part-load standard is applicable during that hour. Determination of the 4-hour emissions standard is calculated by averaging the four previous hourly emission standards. Under this approach, the high hourly load standard would not be applicable until a minimum of 6 continuous operating hours. The initial and final hours would be startup and shutdown, respectively, and the part-load standard is applicable during those hours. If the combustion turbine were operating at high loads during the middle 4 hours, the high load standard would be applicable to that 4-hour average. The emission standards for the remaining hours would be a blended standard that is between the part-load and high-load standards. This approach was viewed as appropriate to account for the different applicable BSERs. Subpart KKKK also includes a 30-operating-day rolling average standard that is applicable to combustion turbines with a HRSG. The 30-operating-day rolling average was included in subpart KKKK because the HRSG was part of the affected facility and a longer averaging period is necessary to account for variability when complying with the alternate output-based emissions standard.

The EPA is proposing to use the same short-term 4-hour standard in new subpart KKKKa along with the blended standard approach. Specifically, the applicable emissions standard would be based on the heat input weighted average of the four applicable hourly emissions standards. However, the EPA

[25] The ambient temperature of combustion turbines located north of the Arctic Circle would often be below 0 °F, and these units are included in the low ambient temperature subcategory regardless of the actual ambient temperature. The costs of requiring combustion controls that would rarely be used are determined not to be reasonable.

[26] Combustion turbines have multiple modes of operation that are applicable at different operating loads and when the combustion turbine is changing loads. The modes are specific to each combustion turbine model. The identified BSER of diffusion flame combustion also includes periods of operation that use less effective DLN compared to operation at high loads.

is proposing two changes to the part-load subcategory. First, the CEMS data analyzed by the EPA indicates that emissions tend to slowly increase at lower loads, but, in general, combustion turbines are capable of maintaining emission rates at loads of 70 percent and greater rather than at loads of 75 percent or greater, as reflected in subpart KKKK. Therefore, the EPA is proposing in subpart KKKKa that this subcategory applies for any hour when the heat input is less than or equal to 70 percent of the base load rating. The EPA notes that since emission rates increase at lower loads, lowering the part-load threshold would bring more operating periods under the high-load subcategory. It could also result in a higher numeric standard. Longer averaging periods reduce, but do not eliminate, the need for a part-load standard. Even under a 30-operating-day average, combustion turbines will, on occasion, have to operate under part-load conditions for relatively long periods. Establishing an emissions rate that includes all periods of operation and that is achievable decreases the emission reduction required for combustion turbines operating at high hourly capacity factors.[27] Establishing absolute mass-based limits is one potential approach to reduce emissions during all periods of operation. In the *Additional Requests for Comment* section below, the EPA is soliciting comment on mass-based standards in addition to short-term emission rates to address any regulatory incentive for owners or operators to reduce operating loads so that the part-load standard is applicable.

Second, the EPA is proposing a different size threshold for subcategorizing the part-load emission standards. Existing subpart KKKK subcategorizes the part-load emissions standard based on the rated output of the turbine (*i.e.,* combustion turbines with outputs greater than 30 MW have a more stringent part-load standard than smaller combustion turbines). New subpart KKKKa proposes to subcategorize the part-load standard based on the heat input rating (*i.e.,* turbines with base load heat input ratings greater 250 MMBtu/h would have a more stringent standard than smaller combustion turbines).

In addition to these two proposed changes from subpart KKKK, the EPA is soliciting comment on a number of topics and concerns associated with the part-load subcategory. Currently, there are no limits on the number of hours per year that a combustion turbine could remain in part-load operation and thus gain the benefit of the part-load emissions standard. In this respect, we note that the threshold for the part-load subcategory, even though proposed to be reduced to 70 percent for subpart KKKKa, remains 30 percent higher than what would be considered ''base load'' operation if measured on an annual basis (*i.e.,* a 40 percent capacity factor). Further, the BSER for the part-load subcategory is diffusion flame technology, and the associated emissions standards for that BSER are substantially less stringent than the standards that would apply in non-part load operation. In fact, the proposed part-load standard for small combustion turbines of 150 ppm NO_X is 50 times less stringent than the 3 ppm standard for such turbines operating at base load on a 12-calendar-month capacity factor basis (which assumes SCR operation in conjunction with combustion controls). Likewise, the proposed part-load NO_X standard for medium and large combustion turbines of 96 ppm is 32 times less stringent.

The EPA requests comment on measures that can be taken to reduce this discrepancy and/or to narrow the scope of application of the part-load standard so as to eliminate perverse incentives to take advantage of a grossly less stringent emissions standard. The EPA requests comment on a maximum limit to the number of hours per year that the part-load standard can be applied. The EPA requests comment on limiting the part-load standard only to those hours when a combustion turbine is in startup or shutdown mode of operation. The EPA requests comment on longer averaging times coupled with the elimination or shrinking of this subcategory so that the emissions standards are set in such a way that they can be complied with even when combustion turbines are in part-load status.

Furthermore, the EPA requests comment on the efficacy of combustion control technology operated in conjunction with SCR when units are in part-load operation. The EPA notes that while there may be some loss in efficiency in combustion controls or in SCR performance in part-load operation, these technologies do not lose all value. Therefore, the EPA requests comment on whether it is appropriate to exclude these technologies from the BSER for part-load operation. If it is not appropriate, then the EPA requests comment on what emissions performance these technologies can achieve in part-load operation. The EPA notes that even if there is some reduction in efficiency, combustion controls in combination with SCR could still achieve emissions rates in part-load operation as low as 9 ppm or 3 ppm, thus calling into question whether emissions rates as high as 96 ppm or 150 ppm would be unjustified to sustain.

With respect to the use of longer averaging periods, the EPA believes these could potentially be a part of the solution if the emission standards were set at such a level that they accommodate some part-load hours of operation where there is lower emissions control efficiency. However, under this approach, this may not entirely remove the need for a part-load standard. Even under a 30-operating-day average, combustion turbines will on occasion have to operate under part-load conditions for relatively long periods. Establishing an emissions rate that includes all periods of operation and that is achievable poses an equally concerning request that it would reduce the stringency of the emissions reductions that are required for combustion turbines operating at high hourly capacity factors.

With this concern in mind, the EPA also requests comment on whether a mass-based emissions standard set over a longer period, such as monthly or annually, could effectively ensure that part-load operation is kept to a minimum so that an overall environmental result is achieved that is in line with the more stringent emissions rates associated with the EPA's proposed BSER determinations that include combustion controls and SCR. Absolute mass-based limits can incentivize reduced emissions during all periods of operation. In such an approach, a mass-based cap would be established through multiplying an assigned emissions rate that factors in some degree of part-load operation by a reasonable assumption concerning operating levels over the period in question. In the *Additional Requests for Comment* section, the EPA is soliciting comment on mass-based standards in addition to short-term emission rates. Among the reasons why such an approach may be both environmentally effective and also reduce regulatory burdens, as discussed in that section, is that any such approach could be tailored to effectively address any regulatory incentive for owners/operators to reduce operating loads so that the part-load standard is applicable.

Additionally, in subpart KKKKa, the EPA is proposing to maintain the same ambient temperature subcategorization

[27] A single emissions standard that applies at all times would presumably need to be set at a numeric level that accounts for the highest hourly emission rates—typically during startup and shutdown.

and BSER as in subpart KKKK. If at any point during an operating hour the ambient temperature is below 0 °F, or if the combustion turbine is located north of the Arctic Circle, the BSER is the use of diffusion flame combustion with the corresponding part-load standard. However, many of the same concerns associated with the part-load standard could be of concern with the ambient temperature subcategorization. For instance, it may be that while combustion controls and SCR lose some performance in these cold conditions, they can still effectively reduce emissions to a substantially greater degree than diffusion flame technology alone. Therefore, the EPA similarly requests comment on whether any of the factors or approaches described above in conjunction with limiting the loss in stringency associated with the part-load subcategory could appropriately be applied to the ambient temperature subcategorization.

g. Subcategory for HRSG Units Operating Independent of the Combustion Turbine

The affected facility under subpart KKKK (and the proposed affected facility under subpart KKKKa) includes the HRSG of combined heat and power (CHP) and combined cycle facilities. Although not common practice, it is possible that the HRSG could operate and generate useful thermal output while the combustion turbine itself is not operating. In subpart KKKK, the EPA subcategorizes this type of operation and bases the NO_X emissions standard on the use of combustion controls for a steam generating unit under one of the steam generating unit NSPS. The EPA is proposing to maintain the same approach in subpart KKKKa and to subcategorize operation of the HRSG independent of the combustion turbine engine with the same emissions standard as in subpart KKKK.

5. Form of the Standard

The form of the concentration-based NO_X standards of performance in subpart KKKK is based on parts per million (ppm) corrected to 15 percent O_2 and the form of alternate output-based NO_X standards is determined on a pounds per megawatt hour-gross (lb/MWh-gross) basis. Also, manufacturer guarantees are often reported in ppm and operating permits are often issued in ppm. Aligning the form of the NSPS with common practice simplifies understanding of the emission standards and reduces burden to the regulated community. While not the primary form of the standard, the alternate output-based form of lb/MWh-gross recognizes the environmental benefit of highly efficient generation.

In new subpart KKKKa, the EPA is proposing input-based NO_X standards in the form of pounds per million British thermal units (lb/MMBtu) and alternate output-based standards in both a gross- and net-output form. As described in the hydrogen combustion section (III.B.14), co-firing hydrogen can increase the NO_X emissions rate on a ppm basis when corrected to 15 percent O_2 while absolute NO_X emissions may not significantly change. Since actual emissions to the atmosphere are the measure of environmental impacts, the NO_X emission standards in the form of lb/MMBtu is a superior measure of environmental performance when comparing emissions from different fuel types. However, throughout this document, the EPA refers to NO_X emission rates using ppm for ease of comparison with performance guarantees and permitted emission rates. The actual proposed standards in new subpart KKKKa are in the form of an equivalent lb/MMBtu for a natural gas-fired combustion turbine or a distillate oil-fired combustion turbine for the proposed natural gas- and non-natural gas-fired NO_X emission standards, respectively.

Consistent with the final Carbon Pollution Standards, the EPA is proposing in subpart KKKKa that the alternate output-based standards be in the form of both gross- and net-output. Net output is the combination of the gross electrical (or mechanical) output of the combustion turbine engine and any output generated by the HRSG minus the parasitic power requirements. A parasitic load for a stationary combustion turbine represents any of the auxiliary loads or devices powered by electricity, steam, hot water, or directly by the gross output of the stationary combustion turbine that does not contribute to electrical, mechanical, or thermal output. One reason for including alternate net-output based standards is that while combustion turbine engines that require high fuel gas feed pressures typically have higher gross efficiencies, they also often require fuel compressors that have potentially larger parasitic loads than combustion turbine engines that require lower fuel gas pressures. Gross output is reported to CAMPD and the EPA can evaluate gross-output based emission rates directly.[28] While this emissions rate is representative of combined cycle turbines without carbon capture and storage (CCS) equipment, the Carbon Pollution Standards require all new base load combustion turbines to install CCS by 2032. To account for the efficiency loss due to CCS, the EPA proposes to use the ratio of the National Energy Technology Laboratory (NETL) combined cycle model plants. Specifically, the achievable gross-output efficiency will be determined by reviewing reported hourly data. The ratio of the NETL combined cycle turbine without CCS gross efficiency will be compared to the NETL combined cycle turbine with CCS gross and net efficiency. These ratios will be multiplied by the reported gross-output emission rate values to determine the proposed alternate output-based standards. As an alternative to continuously monitoring parasitic loads, the EPA is proposing in new subpart KKKKa that estimating parasitic loads is adequate and would minimize compliance costs. A calibration would be required to determine the parasitic loads at four load points: less than 25 percent load; 25 to 50 percent load; 50 to 75 percent load; and greater than 75 percent load. Once the parasitic load curve is determined, the appropriate amount would be subtracted from the gross output to determine the net output. The EPA is requesting comment on this approach and whether a four-load test is appropriate or whether a curve fit of three loads greater than 25 percent load is sufficient.

6. Averaging Period

As described previously, the NO_X emission standards in existing subpart KKKK are based on a 4-hour rolling average for simple cycle turbines and a 30-operating-day average for combustion turbines with a HRSG (*e.g.,* combined cycle and CHP combustion turbines). For this review of the NSPS, the EPA analyzed hourly emissions data using three averaging periods—a 4-hour rolling average, an operating-day average, and a 30-operating-day average. The EPA is proposing in new subpart KKKKa that the emission standards for all combustion turbines complying with the input-based standard (lb NO_X/MMBtu) would be determined on a 4-hour rolling average. According to the EPA's review of hourly emissions data, combustion turbines using combustion controls alone and combustion controls in combination with SCR have a relatively steady emissions profile. The Agency is proposing that shortening the compliance period for combined cycle and CHP units would provide similar levels of environmental protection as the current averaging periods in subpart KKKK. Permits are often based on daily operations and the EPA is soliciting

[28] Net output is not reported to CAMPD.

comment on whether aligning these periods could reduce the reporting burden. To avoid situations where the daily average would be based on limited data that does not account for variability, emissions averages would only be determined for operating days with 4 or more hours of CEMS data that are not out-of-control. Data from operating days with fewer than 4 hours of CEMS data that are not out-of-control would be rolled over to the next operating day until 4 or more hours of data are available. A benefit of this approach is that all non-out-of-control emissions data would be used in determining excess emissions. Under the subpart KKKK approach, any 4 operating hours with more than 1 hour of monitor downtime is reported as monitor downtime and the emissions from the remaining hours are excluded. The EPA proposes to carry this approach forward in proposed subpart KKKKa. However, this could potentially exclude reliable monitoring data and complicate determinations that emissions are in or out of compliance with the emissions standards. Thus, in the alternative, the EPA is soliciting comment on basing compliance for all combustion turbines on a 4-hour rolling average basis where only those hours with monitor downtime are excluded.

Subpart KKKK currently includes alternate gross output-based standards that owners and operators can elect to comply with instead of the input-based standard. The output-based standard was determined using an efficiency that is representative of a combined cycle turbine, so, in practice, only owners and operators of combined cycle or CHP facilities would elect to use the output-based standard. The EPA is proposing to include output-based standards, on both a gross- and net-output basis, as an alternative to the heat input-based standards. Owners and operators electing to use the output-based standards would demonstrate compliance on a 30-operating-day average. The longer averaging period is appropriate because both the NO_X emissions rate on a lb NO_X/MMBtu basis and the efficiency of the combustion turbine can vary—increasing the overall variability.

7. Proposed Determinations of the BSER for New, Modified, and Reconstructed Stationary Combustion Turbines in 40 CFR Part 60, Subpart KKKKa

Sections III.B.7 through III.B.11 describe the EPA's proposed BSER determinations for the different size-based subcategories in subpart KKKKa based on a review of demonstrated NO_X emission control technologies. The following sections describe each of the proposed combustion turbine subcategories and each proposed BSER technology determination. The control technologies the EPA evaluated for each size-based subcategory, whether the combustion turbine operates as a low load, intermediate load, or base load unit, or whether the combustion turbine burns natural gas or non-natural gas fuels, include: dry combustion controls (*i.e.,* lean premix/DLN), wet combustion controls (*i.e.,* water or steam injection) (together, ''combustion controls''), and post-combustion SCR. In sections III.B.7.a and III.B.7.b, the EPA describes the basic characteristics and performance of dry and wet combustion controls and then SCR, including information concerning costs. In sections III.B.9 through III.B.11, the EPA applies the BSER criteria for these two general technology types, including further consideration of costs, emission reductions, and non-air quality health and environmental impacts and energy requirements, as applied to the small, medium, and large subcategories proposed for NO_X in subpart KKKKa.

Under the existing NSPS in subpart KKKK, newly constructed stationary combustion turbines are subject to more stringent NO_X emission standards than reconstructed and modified combustion turbines. The proposed subcategorization approach in subpart KKKKa does not maintain this structure. Specifically, in subpart KKKKa, the EPA is proposing that the same BSER and NO_X emission standards are applicable to both new and reconstructed combustion turbines, regardless of the subcategory. In addition, the EPA is proposing that the BSER and NO_X emission standards for ''modified'' sources are the same as for the corresponding new and reconstructed sources for certain subcategories, and different for others as explained in more detail below in section III.B.13. The EPA is proposing to use the same emissions analysis for both new and reconstructed stationary combustion turbines. For each of the subcategories, the EPA is proposing that the proposed BSER results in the same standard of performance for new stationary combustion turbines and reconstructed stationary combustion turbines because reconstructed turbines could likely incorporate technologies to reduce NO_X as part of the reconstruction process at little or no cost compared to a greenfield facility.

Under the EPA's General Provisions for the NSPS program, a reconstructed source would still be able to obtain an alternative emissions standard on a case-by-case basis. A reconstructed stationary combustion turbine is not required to meet the standards if doing so is deemed to be ''technologically and economically'' infeasible.[29] This provision requires a case-by-case reconstruction determination in the light of considerations of economic and technological feasibility. However, this case-by-case determination would consider the identified BSER, as well as technologies the EPA considered, but rejected, as BSER for a nationwide rule. One or more of these technologies could be technically feasible and of reasonable cost, depending on site-specific feasibility.

The EPA is proposing in new subpart KKKKa that for small natural gas-fired stationary combustion turbines (*i.e.,* those with base load ratings of less than or equal to 250 MMBtu/h of heat input) operating as base load units (*i.e.,* at 12-calendar-month capacity factors of greater than 40 percent), the BSER is dry combustion controls in combination with SCR. The EPA is proposing wet combustion controls in combination with SCR as the BSER for small, base load, non-natural gas-fired stationary combustion turbines. However, for small combustion turbines operating at low or intermediate loads (*i.e.,* at 12-calendar-month capacity factors of less than or equal to 40 percent), the proposed BSER is dry combustion controls for natural gas-fired units and wet combustion controls for non-natural gas-fired units. The proposed BSER for small low and intermediate load combustion turbines does not include SCR.

In new subpart KKKKa, for medium stationary combustion turbines (*i.e.,* those with base load ratings greater than 250 MMBtu/h of heat input and less than or equal to 850 MMBtu/h) the EPA is proposing that the BSER is dry or wet combustion controls in combination with SCR for both natural gas-fired and non-natural gas-fired combustion turbines. However, for medium stationary combustion turbines that operate as low load units (*i.e.,* at 12-calendar-month capacity factors of less than or equal to 20 percent) and that are natural gas-fired, the EPA is proposing that the BSER is dry combustion controls and does not include SCR. The EPA is proposing that the BSER for medium, low load, non-natural gas-fired combustion turbines is wet combustion controls and does not include SCR.

The EPA is proposing in new subpart KKKKa that for large stationary combustion turbines (*i.e.,* those with base load ratings greater than 850 MMBtu/h of heat input) that operate at

[29] See 40 CFR 60.15(b)(2).

intermediate or high loads (*i.e.,* at 12-calendar-month capacity factors of greater than 20 percent), the BSER is dry or wet combustion controls in combination with SCR for both natural gas-fired and non-natural gas-fired combustion turbines. Additionally, in subpart KKKKa, the EPA is proposing that for large stationary combustion turbines that operate at low loads (*i.e.,* at 12-calendar-month capacity factors of less than or equal to 20 percent) and that are natural gas-fired, the BSER is dry combustion controls and does not include SCR. The EPA is proposing that the BSER for large, low load, non-natural gas-fired combustion turbines is wet combustion controls and does not include SCR.

TABLE 1—PROPOSED BSER AND NO_X EMISSION STANDARDS

Combustion turbine type	Combustion turbine fuel	BSER	NO_X emission standard (lb/MMBtu)	NO_X emission rate equivalent (ppm)
New or reconstructed with capacity factor ≤40 percent and base load rating ≤250 MMBtu/h.	Natural gas	Combustion controls	0.092	25
	Non-natural gas	Combustion controls	0.290	74
New or reconstructed with capacity factor >40 percent and base load rating ≤250 MMBtu/h.	Natural gas	Combustion controls with SCR.	0.011	3
	Non-natural gas	Combustion controls with SCR.	0.035	9
Modified combustion turbines, all loads with base load rating ≤250 MMBtu/h.	Natural gas	Combustion controls	0.092	25
	Non-natural gas	Combustion controls	0.290	74
New or reconstructed with capacity factor ≤20 percent and base load rating >250 MMBtu/h and ≤850 MMBtu/h.	Natural gas	Combustion controls	0.092	25
	Non-natural gas	Combustion controls	0.290	74
New or reconstructed with capacity factor >20 percent and base load rating >250 MMBtu/h and ≤850 MMBtu/h.	Natural gas	Combustion controls with SCR.	0.011	3
	Non-natural gas	Combustion controls with SCR.	0.035	9
Modified combustion turbines, all loads with base load rating >250 MMBtu/h and ≤850 MMBtu/h.	Natural gas	Combustion controls	0.092	25
	Non-natural gas	Combustion controls	0.290	74
New, modified, or reconstructed with capacity factor ≤20 percent and base load rating >850 MMBtu/h.	Natural gas	Combustion controls	0.055	15
	Non-natural gas	Combustion controls	0.150	42
New, modified, or reconstructed with capacity factor >20 percent and base load rating >850 MMBtu/h.	Natural gas	Combustion controls with SCR.	0.011	3
	Non-natural gas	Combustion controls with SCR.	0.019	5
New, modified, or reconstructed offshore combustion turbines, all sizes and loads.	Natural gas	Combustion controls	0.092	25
	Non-natural gas	Combustion controls	0.290	74
Combustion turbines with base load rating ≤250 MMBtu/h operating at part load, sites north of the Arctic Circle, and/or ambient temperatures of less than 0 °F.	Natural gas or non-natural gas.	Diffusion flame combustion controls.	0.58	150
Combustion turbines with base load rating >250 MMBtu/h operating at part load, sites north of the Arctic Circle, and/or ambient temperatures of less than 0 °F.	Natural gas or non-natural gas.	Diffusion flame combustion controls.	0.37	96
Heat recovery units operating independent of the combustion turbine(s).	Natural gas or non-natural gas.	Combustion controls	0.21	54

a. Dry and Wet Combustion Controls

Combustion turbines without NO_X controls use combustors that are diffusion controlled where fuel and air are injected separately. The resultant diffusion flame combustion can lead to the creation of hot spots that produce high levels of thermal NO_X. In contrast, combustion controls consist of operational or design modifications that govern combustion conditions to reduce NO_X formation. Combustion controls are widely available for new combustion turbines and are generally low cost and provide substantial reductions in NO_X emissions relative to combustion turbines without combustion controls. In subpart KKKK, the EPA identified combustion controls as the BSER for limiting NO_X emissions from stationary combustion turbines firing natural gas and non-natural gas fuels (*e.g.,* distillate oil). The specific technologies described in subpart KKKK for the control of NO_X from natural gas-fired combustion turbines are dry controls based on a lean premix/DLN combustion system. *See* 71 FR 38482; July 6, 2006.

Wet combustion controls (*e.g.,* water injection) are a mature combustion control technology that has been used since the 1970s to control NO_X emissions from combustion turbines. This system involves the injection of water (or steam) into the flame area of the combustion reaction to reduce the peak flame temperature in the combustion zone and limit thermal NO_X formation. Wet control systems are designed to a specific water-to-fuel ratio that has a direct impact on the controlled NO_X emission rate and is generally controlled by the combustion turbine inlet temperature and ambient temperature. Wet control systems have demonstrated the ability to limit NO_X emissions to as low as 25 ppm for stationary combustion turbines firing natural gas and between 42 ppm to 75 ppm for sources firing non-natural gas liquid fuels.

Wet combustion controls can be combined with technologies that decrease the negative impacts of higher ambient temperatures on the efficiency and output of combustion turbine engines and/or that increase the efficiency and output of the combustion turbine engine. Intercooling technologies that inject demineralized water into the combustor through the fuel nozzles also provide NO_X control. Thus, water injected into the combustor flame area lowers the temperature and, consequently, reduces NO_X emissions.[30] Water injection also increases the mass flow rate and the power output, but the energy required to vaporize the water can reduce overall efficiency. In general, the lower capital costs and higher variable costs of water injection compared to other NO_X control technologies make it an attractive option for peaking combustion turbines or other sources that operate infrequently.

Steam injection is like water injection, except that steam is injected into the compressor and/or through the fuel nozzles directly into the combustion chamber instead of water. Steam injection reduces NO_X emissions and has the advantage of improved efficiency and larger increases in the output of the combustion turbine. Multiple vendors offer different variations of steam injection. The basic process uses a relatively simple and low-cost HRSG to produce steam, but instead of recovering the energy by expanding the steam through a steam turbine, the steam is injected into the combustion chamber and the energy is extracted by the combustion turbine engine.[31] Combustion turbines using steam injection have characteristics of both simple cycle and combined cycle units. For example, when compared to standard simple cycle turbines, they are more efficient but more complex with higher capital costs. Conversely, compared to combined cycle combustion turbines, they are simpler and have shorter construction times, have lower capital costs, but have lower efficiencies.[32] [33] Combustion turbines using steam injection can start quickly, have good part load performance, and can respond to rapid changes in demand. A potential drawback of steam injection is that the additional pressure drop across the HRSG can reduce the efficiency of the combustion turbine when the facility is running without the steam injection operating.

Dry low NO_X (DLN) combustion control systems were commercially introduced more than 30 years ago. The basis of dry NO_X control is to premix the fuel and air and supply the combustion zone with a completely homogenous, lean mixture of fuel and air. Lean premix means the air-to-fuel ratio contains a low quantity of fuel, and the DLN combustors in the turbine are designed to sustain ignition of this lean premix air/fuel mixture at a low peak flame temperature, thereby limiting the formation of thermal NO_X. Lean combustion may be combined with staged combustion to achieve additional NO_X reductions. Staged combustion is designed to reduce the residence time of the combustion air in the presence of the flame at peak temperature. The longer the residence time, the greater the potential for thermal NO_X formation. When increasing the air/fuel ratio, excess air is added to the mixture, and not only does this lean the combustion air by adding more air to the air/fuel ratio, but it also decreases the residence time at peak flame temperatures. Dry combustion control systems can typically limit NO_X emission concentrations to 25 ppm, while advanced ultra-low DLN technology can further reduce NO_X emissions to 15 or 9 ppm and to as low as 5 ppm for certain large frame combustion turbine designs. DLN combustion systems are complex and sensitive to the load of the combustion turbine and changes in load. The premixed fuel is typically supplied by multiple injection ports and lean-premix flame zones. A diffusion flame pilot zone is sometimes required to maintain combustion stability in the lean premix zones and contributes to thermal NO_X. During steady State operation the fuel supplied to the pilot zone is minimized. However, during variable load operation and lower loads, it is necessary to increase the percentage of fuel supplied to the pilot zone and NO_X emissions increase above the steady State high load conditions.

DLN is less effective with distillate fuel oil (and other liquid fuels) because distillate fuel oil has a higher peak flame temperature than natural gas and results in higher NO_X formation rates, and it is more challenging to achieve unform mixing of the air and fuel.

b. Selective Catalytic Reduction

Selective catalytic reduction (SCR) is a mature and well understood post-combustion add-on NO_X control that has been installed on combustion turbines (both simple and combined cycle), utility boilers, industrial boilers, process heaters, and reciprocating internal combustion engines. Many stationary combustion turbines in the power sector currently utilize the NO_X reduction capabilities of SCR. For example, based on information reported to the EPA's Clean Air Markets Program Data (CAMPD) in the last five years, SCR has been installed on all new power sector combined cycle combustion turbines and a majority of recent power sector simple cycle combustion turbines.[34] Specifically, of the new power sector simple cycle turbines constructed in the last 5 years, 88 percent (59 of 67) of those smaller than 850 MMBtu/h and 46 percent (11 of 24) of those larger than 850 MMBtu/h have installed SCR. Most simple cycle turbines in the power sector operate at low annual capacity factors (*i.e.,* less than 20 percent).[35] A potential reason why more medium simple cycle combustion turbines have been required to use SCR is because most of these units are aeroderivative designs with guaranteed NO_X emission rates of 25 ppm and potentially higher annual capacity factors. The larger units tend to be frame-type combustion turbines with NO_X guarantees of 15 ppm or 9 ppm. Since the capital costs are more dependent on the controlled emissions rate and not the percent reduction, the incremental control costs of SCR can be higher and emission reductions lower for large frame units relative to medium aeroderivative units. In addition, the exhaust temperature of the most efficient frame-type combustion turbine is approximately 200 °C higher than the most efficient aeroderivative combustion turbines. The exhaust must be cooled prior to the SCR, and so the higher exhaust temperatures increase the cost of the SCR system. The technology can be applied as a standalone NO_X control or combined with other technologies, including the wet and dry combustion controls discussed previously.

The SCR process is based on the chemical reduction of the NO_X molecule via a nitrogen-based reducing agent

[30] In general, the addition of water or steam will not increase emissions of carbon monoxide (CO) or unburned hydrocarbons. However, at higher injection rates, emissions of CO and unburned hydrocarbons can increase.

[31] Innovative Steam Technologies. *GTI.* Accessed at *https://otsg.com/industries/powergen/gti/.*

[32] Bahrami, S., et al (2015). *Performance Comparison between Steam Injected Gas Turbine and Combined Cycle during Frequency Drops.* Energies 2015, Volume 8. *https://doi.org/10.3390/en8087582.*

[33] Mitsubishi Power. *Smart-AHAT (Advanced Humid Air Turbine.* Accessed at *https://power.mhi.com/products/gasturbines/technology/smart-ahat.*

[34] See the U.S. Environmental Protection Agency's (EPA) Clean Air Markets Program Data at *https://campd.epa.gov/data.*

[35] Based on operating data reported to the EPA's Clean Air Markets Program Data, the EPA projects that approximately 10 percent of simple cycle turbines would operate at 12-calendar-month capacity factors of greater than 20 percent and would be subcategorized as intermediate load combustion turbines. The proposed BSER for this subcategory is based on the use of combustion controls in combination with SCR. All of the projected intermediate load simple cycle turbines are aeroderivative designs and have SCR in the base case.

(reagent) and a solid catalyst. To remove NO_X, the reagent, commonly ammonia (NH_3, anhydrous and aqueous) or urea-derived ammonia, is injected into the post-combustion flue gas of the combustion turbine. The reagent reacts selectively with the flue gas NO_X within a specific temperature range and in the presence of the catalyst and oxygen to reduce the NO_X into molecular nitrogen (N_2) and water vapor (H_2O). SCR employs a ceramic honeycomb or metal-based surface with activated catalytic sites to increase the rate of the reduction reaction. Over time, however, the catalyst activity decreases, requiring replacement, washing/cleaning, rejuvenation, or regeneration to extend the life of the catalyst. Catalyst designs and formulations are generally proprietary. The primary components of the SCR include the ammonia storage and delivery system, ammonia injection grid, and the catalyst reactor.

The EPA's review of combustion turbine emissions data and applied control technologies for this proposed NSPS demonstrates a correlation between the efficiency of new turbine designs and NO_X emissions using combustion controls. For example, manufacturers have continuously strived to increase the efficiency of new turbine designs. However, manufacturer specification sheets show that some models of large, high-efficiency turbines cannot meet the 15 ppm NO_X standard established in subpart KKKK. A review of power sector data reported to EPA's CAMPD—as well as BACT permits under the NSR program—shows that many owners/operators of high-efficiency combustion turbines subject to a NO_X limit of 15 ppm have installed SCR. This correlation between high-efficiency combustion turbines and increased NO_X emissions has led to SCR becoming a more utilized control technology for the source category.

As discussed in more detail in sections III.B.9 through III.B.11, available data indicates that SCR installed on stationary combustion turbines, when operated in conjunction with combustion controls, is generally capable of achieving a NO_X emissions rate of 3 ppm, at least when combustion turbines are operating at intermediate or base loads. Therefore, in general, for those subcategories of stationary combustion turbines for which the EPA is proposing SCR as a component of the BSER and which are firing natural gas, the EPA is proposing an emissions standard of 3 ppm. However, the EPA is soliciting comment on a range of possible emissions rates, from 2 to 5 ppm, recognizing the potential for some variation in SCR performance among units and operating conditions.[36] The EPA notes that effectiveness of SCR can be impacted by load changes. During variable load operation the absolute mass of NO_X entering the SCR system, the temperature of the combustion turbine exhaust, and exhaust flow characteristics change. SCR performance is impacted by catalyst temperature and flow characteristics and the ammonia injection rate must be adjusted to maintain the exhaust NO_X emissions concentration. Too much ammonia injection can result in excess ammonia emissions (*i.e.,* ammonia slip) and too little can result in higher NO_X emissions. The EPA is soliciting comment on if it can be challenging to adjust ammonia injection rates during rapid load changes to maintain NO_X emissions rates while at the same time minimizing ammonia slip, particularly for combustion turbines not selling electricity to the electric grid.

The EPA also invites comments on methods for control of ammonia emissions from SCR operation more broadly. The EPA is not proposing to establish a BSER or standards of performance for ammonia emissions from stationary combustion turbines. However, the EPA is soliciting comment on opportunities to reduce ammonia emissions—either through operational changes or though incorporation of downstream ammonia control technology. The EPA requests comment on the commercial availability, cost, and performance of technologies that reduce the amount of ammonia emitted in association with SCR operation. The EPA requests comment on whether there are practices associated with SCR operation to limit ammonia emissions based on these technologies or other approaches. The EPA also solicits comment on whether there are disbenefits of using ammonia emission control technologies. The EPA further discusses specific estimates of ammonia emissions associated with SCR operation in its size-based subcategory discussions of the BSER in sections III.B.9.b.iv, III.B.10.b.iv, and III.B.11.b.iv of this document.

In 2006, when subpart KKKK was promulgated, SCR was evaluated as a potential best system, and based on a relatively limited review of the available information at the time, was viewed to not meet the statutory criteria. The available information suggested that the cost of achieving incremental reductions in NO_X emission concentrations with the use of SCR was relatively high on a per-ton basis compared to the lean premix/DLN systems that were the dominant controls in the combustion turbine marketplace at that time. Stack test data and manufacturer guarantees confirmed that newer large combustion turbines without add-on controls could achieve NO_X emission concentrations as low as 9 ppm while SCR could achieve NO_X emission concentrations of 2 to 4 ppm. Furthermore, for SCR to effectively remove NO_X from the combustion turbine exhaust, the system's catalyst must reach a minimal operating temperature. For peaking units or combustion turbines operating under variable loads, the EPA understood it to be challenging for the SCR catalyst to reach or to maintain the required operating temperature, and the EPA had not developed the approach to subcategorization that it applied in the Carbon Pollution Standards and is now proposing in this action, which would distinguish between low, intermediate, and base load levels of utilization. Therefore, based on the analysis at the time, it was determined in subpart KKKK that SCR could be too difficult and not incrementally cost effective on a per-ton basis to implement for certain combustion turbines.

As will be detailed below in the subcategory-specific review of SCR technology as BSER for NO_X, the EPA has undertaken a careful review of the BSER factors in relation to SCR, and proposes to determine that SCR is generally a part of the BSER for stationary combustion turbines, except for small turbines that only operate at low or intermediate loads on a 12-calendar-month basis and medium and large turbines that only operate at low loads on a 12-calendar-month basis. A review of recent rules and determinations, multiple other cost metrics that are relevant to consider, and the widespread adoption of this technology across many types and sizes of power sector stationary combustion turbines in recent years, all contribute to support our determination that this technology is cost-reasonable for the subcategories of turbines to which we propose to apply it as BSER in subpart KKKKa.

There are a number of indicators that broadly support the cost-reasonableness of SCR as a part of the BSER for stationary combustion turbines of all sizes.

[36] An emissions rate of 5 ppm could also potentially be met by some stationary combustion turbines solely with the use of combustion controls rather than SCR. Given that SCR has some additional cost, pollutant, and energy impacts associated with it, there could be benefit to a standard that at least some sources may be capable of meeting without installing SCR. However, this observation does not negate the EPA's proposed determination that SCR satisfied the BSER statutory criteria.

First, as described above, SCR is already widely adopted as an emissions control strategy for many types and sizes of stationary combustion turbines, with 100 percent of all new combined cycle units and approximately 75 percent of all new simple cycle units in the power sector installing SCR in the last 5 years. The EPA found the information contained in the records of permitting actions requiring SCR on turbines to not be particularly well developed for purposes of informing a detailed cost analysis. However, all of the instances where sources have chosen to install SCR and go forward with their new turbine project or installation (whether because required by a permitting authority or for voluntary reasons) underscores that SCR costs do not undermine the economic viability of new combustion turbine projects. From that perspective, the costs are clearly reasonable. If the costs were not reasonable, then one would expect that developers would abandon their combustion turbine projects once SCR was required. Instead, we have seen widespread adoption in the power sector.

Second, the costs of SCR as a percentage of the total capital cost associated with constructing a new combustion turbine are relatively low. As described in more detail in the subcategory-specific discussions of SCR costs further in this section, the EPA estimated that the spent capital cost of including an SCR into the design of a new small or medium stationary combustion turbine is typically around $2 million to $4 million (2018$), depending on the SCR type. The estimation of spent capital cost is approximately $4 million to $10 million (2018$) depending on SCR type for large units. These costs typically represent approximately 1 to 4 percent of the total cost of a new stationary combustion turbine.[37] In the EPA's judgment, and as reflected in the widespread adoption of SCR technology in the power sector already, these costs on either an absolute basis or as a percentage of capital investment, are reasonable. The EPA is not aware of any reasons why the costs for adoption of SCR technology on newly constructed non-power sector combustion turbines would be different from adoption on newly constructed and comparably-sized power sector combustion turbines. The EPA solicits comment on whether there are such reasons or circumstances where the costs of SCR adoption would be different for comparably-sized combustion turbines constructed in the power sector and in non-power industrial sectors.

Third, these costs translate into a relatively low cost per unit of energy output and thus, in terms of their effect on prices or cost to the consumer, are relatively small and manageable. Total costs (annualized capital costs, fixed costs, and operating costs) in terms of cost per unit of production (in terms of electricity generation) translate into $3/MWh and $1/MWh, respectively, for a 50 MW simple cycle combustion turbine operating at a 12-operating-month capacity factor of 30 percent and a 400 MW combined cycle combustion turbine operating at a 12-operating-month capacity factor of 60 percent, respectively. These cost effects on generation compare favorably with prior EPA rules. For example, the EPA identified $8.50/MWh in selecting CCS as the BSER for certain new stationary combustion turbines in the recently promulgated Carbon Pollution Standards. *See* 89 FR 39798; May 9, 2024. Likewise, in the Carbon Pollution Standards for coal-fired EGUs, the EPA identified $18/MWh in selecting CCS for that category, noting that this cost per unit of generation compared favorably with a value of $18.50/MWh identified with the control stringency for EGUs identified in the original Cross-State Air Pollution Rule (CSAPR). *See* 89 FR 39879, 39882.

Fourth, costs on a per-ton basis also compare favorably with prior EPA rulemakings regulating NO_X emissions. Although determinations concerning cost reasonableness in one statutory or programmatic context may not necessarily translate to another, these regulatory precedents offer points of comparison with respect to the same pollutant that can be informative in evaluating the most cost-effective opportunities for abatement of a common pollutant across multiple program arenas. As described in more detail in the subcategory-specific sections below, the EPA has identified a cost of $12,000 per ton of NO_X abated as the cost effectiveness range for small units operating at base load; a range of $12,000 to $5,100 per ton of NO_X abated as the cost effectiveness range for medium units operating at intermediate or base load, respectively; and $8,400 to $3,800 per ton of NO_X abated as the cost effectiveness range for large units operating at intermediate and base load, respectively. As described in further detail in those sections, these costs increase against a higher controlled baseline. Nonetheless, in new subpart KKKKa, for those subcategories for which the EPA proposes SCR as the BSER, these costs per ton are comparable to more recent determinations of cost effectiveness for NO_X control, particularly following the strengthening of the ozone NAAQS in 2015 to be more protective of human health and the environment. For instance, the proposed SCR costs are generally lower than the estimated SCR costs for retrofit applications in the *Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard* rulemaking, where the EPA identified $11,000/ton of NO_X as the appropriate representative cost threshold for defining ''significant contribution'' under CAA section 110(a)(2)(D)(i)(I). That is the representative cost for the retrofit of SCR on coal-fired EGUs, which reflects a fleetwide average with individual units' costs ranging higher or lower than the fleetwide average. *See* 88 FR 36654, 36746; June 5, 2023. As the EPA explained in that action, its determinations of emissions control stringency for upwind States were generally in accordance with the technology-based emissions control determinations in areas struggling with high ozone levels. *Id.* at 36661, 36838. Indeed, the EPA recognized that costs on an individual unit basis may range higher than $20,000/ton on a unit-specific basis and yet still be justified, particularly where the control technology itself is no different, and those cost-per-ton figures are merely driven by operational choices of the relevant units. *Id.* at 36746–47. In such circumstances where units are of such a size that they have the *potential* to emit at much higher levels if they were to operate more, the EPA explained that cost-per-ton figures based on historical operational data would not supply an appropriate justification not to ensure that such sources meet an appropriate uniform level of emissions performance that like sources would be subject to. *Id.* The EPA notes that estimated reductions, costs, and cost effectiveness of SCR in this proposal are based on short-term achievable emission standards as opposed to estimated longer term emission rates. Combustion turbines with guaranteed NO_X emission rates, which are only guaranteed under certain conditions, have long-term emission rates lower than the guaranteed levels. For example, combustion turbines with guaranteed NO_X emission rates of 25 ppm, 15 ppm, and 9 ppm have long-term emission

[37] The estimated as spent capital costs of SCR vary with the type of the SCR (hot or conventional) size of the combustion turbine, but the estimated capital costs are approximately $70/kilowatt (kW) for a 50 MW simple cycle turbine and $10/kW for a 400 MW combined cycle turbine.

rates of 20 ppm, 14 ppm, and 7 ppm NO_X, respectively. Similarly, combustion turbines with SCR and complying with a short-term emissions standard of 3 ppm NO_X have long-term emission rates of 2 ppm NO_X. Using long-term averages for the benefits and costs would on average increase incremental control costs.

Similarly, here, viewing the data concerning the costs as well as the widespread deployment and efficacy of SCR technology for combustion turbines as a whole, the EPA proposes that, with the exception of specified circumstances of relatively permanent (*i.e.,* 12-calendar-month) low-load and low-emissions operating conditions, SCR is an adequately demonstrated and cost effective NO_X emissions control technology that can readily be deployed on new, reconstructed, and modified stationary combustion turbines of all sizes and is therefore appropriate to include as a component of the BSER. For this technology review, the EPA estimated the capital and operating costs of SCR primarily using information from the U.S. Department of Energy's (DOE) NETL flexible generation report.[38] The NETL report includes detailed costing information on aeroderivative simple cycle turbines using hot SCR and frame combined cycle turbines using conventional SCR. For information not available in the NETL report, the EPA used information for SCR costs on natural gas-fired boilers and Agency engineering judgment. For detailed information on the costing analysis, see the SCR costing technical support document included in the docket for this proposal. More detailed cost-per-ton and other related cost figures will be discussed in the subcategory-specific sections below, including specific solicitations for comment on aspects of the EPA's cost estimates for certain stationary combustion turbines.

8. BSER for Combustion Turbines Operating at Part Loads, Located North of The Arctic Circle, or Operating at Ambient Temperatures of Less Than 0 °F

Dry combustion controls (*i.e.,* lean premix/DLN) are less effective at reducing NO_X emissions at part-load operations and low ambient temperatures. In addition, SCR is only effective at reducing NO_X under certain temperatures at part loads and is not as effective at reducing NO_X as at design conditions. The only technology the EPA has identified for all part-load operation and/or low ambient temperatures is the use of diffusion flame combustion. Therefore, in subpart KKKKa, the EPA is proposing that diffusion flame combustion is the BSER for these conditions.[39]

9. BSER for Small Combustion Turbines

This section describes the proposed BSER determinations for new and reconstructed small stationary combustion turbines with base load ratings of less than or equal to 250 MMBtu/h of heat input. For combustion turbines that would be included in this subcategory, the proposed BSER is the use of dry or wet combustion controls in combination with SCR when operating as base load units (*i.e.,* at 12-calendar-month annual capacity factors greater than 40 percent). For combustion turbines in this small size subcategory operating at low or intermediate loads (*i.e.,* at 12-calendar-month annual capacity factors of less than or equal to 40 percent), the proposed BSER is the use of dry combustion controls (*i.e.,* lean premix/dry low NO_X (DLN)) when firing natural gas and wet combustion controls (*i.e.,* water or steam injection) when firing non-natural gas fuels.

a. Combustion Controls

This section describes the current availability and performance of dry and wet combustion controls that have been used by owners/operators of small stationary gas and combustion turbines to limit NO_X emissions since the original NSPS (subpart GG) was promulgated in 1979. Both wet and dry combustion controls also were maintained as the BSER in existing subpart KKKK in 2006. This control technology continues to be used on new and reconstructed stationary combustion turbines, including those with base load ratings of less than or equal to 250 MMBtu/h of heat input.

i. Adequately Demonstrated

Dry and/or wet combustion controls are widely available from major manufacturers for combustion turbines with base load ratings of less than or equal to 250 MMBtu/h of heat input. Combustion controls are mature technologies that have been demonstrated for multiple years in various end-use applications, and the EPA proposes to maintain in new subpart KKKKa that combustion controls are adequately demonstrated for this subcategory. Both dry and wet combustion controls have been demonstrated on combustion turbines burning gaseous fuels. However, for liquid fuels such as distillates, dry combustion controls are less effective and only wet combustion controls are proposed to be the BSER.

ii. Extent of Reductions in NO_X Emissions

Manufacturer NO_X emission rate performance guarantees for new natural gas-fired stationary combustion turbines with base load ratings of less than or equal to 250 MMBtu/h of heat input and using dry combustion controls range from 9 ppm to 25 ppm.[40] Combustion turbine designs that would be included in this proposed subcategory with 9 ppm NO_X guarantees tend to be less efficient and/or smaller and the Agency does not consider this level of lean premix/DLN available for the proposed subcategory as a whole. For example, of the 14 commercially available lean premix/DLN combustion turbines with base load ratings of less than or equal to 50 MMBtu/h of heat input, 13 have guaranteed NO_X emission rates of less than or equal to 25 ppm. Since multiple combustion turbines are available with similar rated outputs and with equal or greater design efficiencies (as compared to the single unit with less advanced combustion controls), the EPA is not proposing to include a separate subcategory in new subpart KKKKa for stationary combustion turbines with base load ratings of less than or equal to 50 MMBtu/h of heat input. Instead, these small designs would have the same BSER of combustion controls and would be required to meet the same NO_X standard as larger combustion turbines with base load ratings of less than or equal to 250 MMBtu/h of heat input. As discussed previously in section III.B.4.b, the EPA believes this change from subpart KKKK would have a limited impact on the regulated community because nearly all new models of these smaller combustion turbines have guaranteed NO_X emission rates of 25 ppm or less based on the application of combustion controls. There is a single combustion turbine model on the market with a base load rated heat input of less than 50 MMBtu/h with a NO_X emissions guarantee of 100 ppm, but the EPA is not aware of

[38] Oakes, M.; Konrade, J.; Bleckinger, M.; Turner, M.; Hughes, S.; Hoffman, H.; Shultz, T.; and Lewis, E. (May 5, 2023). *Cost and Performance Baseline for Fossil Energy Plants, Volume 5: Natural Gas Electricity Generating Units for Flexible Operation.* U.S. Department of Energy (DOE). Office of Scientific and Technical Information (OSTI). Available at *https://www.osti.gov/biblio/1973266.*

[39] A BSER of diffusion flame combustion includes DLN that is less effective at reducing NO_X than DLN under design conditions.

[40] Throughout this document, all references to parts per million (ppm) are intended to be interpreted as parts per million volume on a dry basis (ppmvd) at 15 percent O_2, unless otherwise noted.

any recent new installations or reconstructions using this model.[41] However, reducing the emissions standard for combustion turbines of less than or equal to 50 MMBtu/h would reduce emissions for future applications that could have, otherwise, used this 100 ppm combustion turbine.[42] Each combustion turbine complying with the proposed NSPS operating at a 30 percent annual capacity factor would reduce emissions of annual NO_X by approximately 7 tons relative to the subpart KKKK emission standards.

Of the 27 available combustion turbines with dry combustion controls and base load ratings of greater than 50 MMBtu/h of heat input and less than or equal to 250 MMBtu/h, 25 have manufacturer performance guarantees of 25 ppm NO_X or less. Therefore, as discussed below in section III.B.12, the EPA is proposing a BSER of dry combustion controls in this subcategory, the application of which can achieve a 25 ppm NO_X emissions rate.

Given that dry combustion controls are capable of meeting a 15 ppm or even a 9 ppm NO_X emissions rate in certain applications when firing natural gas, the EPA is soliciting comment on whether small combustion turbines utilizing wet combustion controls also can achieve a 15 ppm or lower NO_X emissions rate when firing gaseous fuels. Relatedly, the EPA requests comment on whether there are applications for small natural gas-fired turbines where dry combustion controls are not available such that the EPA should accommodate the continued use of wet combustion controls, at least in some applications. For example, advantages of wet combustion controls can include increased output relative to dry combustion controls and reduced efficiency losses at higher ambient temperatures. Disadvantages can include lower efficiencies and the requirement to use large volumes of demineralized water. The EPA is soliciting comment on whether these relative advantages/disadvantages make water injection most applicable to small, low load turbines. The EPA is soliciting comment on whether small combustion turbines using steam injection can achieve an emissions rate of 15 ppm NO_X when firing natural gas. The EPA also is soliciting comment on whether steam injection should be a potential BSER for small stationary combustion turbines operating at intermediate loads and firing natural gas. For example, combustion turbine designs are available that use steam injection in combination with water recovery that reduces the need for demineralized water and could improve the economics of wet combustion controls for small stationary combustion turbines that would operate at intermediate loads.

The EPA is not aware of any advances in combustion controls that would further reduce NO_X emissions for small low and intermediate load combustion turbines firing non-natural gas-fired fuels. Therefore, the EPA is proposing to maintain that the wet combustion controls identified in subpart KKKK continue to be the BSER in new subpart KKKKa.

iii. Costs

The use of combustion controls that can achieve 25 ppm NO_X emission rates have been standard for electric and industrial applications of natural gas-fired stationary combustion turbines sold nationwide for multiple years, and combustion controls, consistent with the standards promulgated in subpart KKKK represent minimal costs to the regulated community.

Therefore, in new subpart KKKKa, the EPA maintains that costs associated with a 25 ppm standard are clearly reasonable for the proposed subcategory of natural gas-fired stationary combustion turbines with a base load rating of less than or equal to 250 MMBtu/h of heat input.

At this time, the Agency does not have detailed data on the capital or operating and maintenance (O&M) costs for small natural gas-fired combustion turbines with dry combustion controls and NO_X guaranteed emission rates of 15 ppm or less relative to the costs of comparable combustion turbines with 25 ppm NO_X emission rate guarantees. In this proposal, the EPA is soliciting information on those capital and O&M costs. To the extent the Agency receives information that the costs of dry combustion controls for small natural gas-fired combustion turbines with emission rates of 15 ppm NO_X or lower are reasonable—as compared to those with emission rates of 25 ppm NO_X—the Agency may finalize NO_X emission standards consistent with these more stringent guaranteed levels in conjunction with a determination that dry combustion controls alone are the BSER for small turbines or some subcategory of small turbines. The EPA is also soliciting additional information on potential impacts of lower NO_X-emitting combustors on the operation of small combustion turbines. In particular, the Agency is seeking information on potential reductions in efficiency and/or output of dry combustion controls that are capable of achieving 15 ppm NO_X or less.

Based on design information in *Gas Turbine World 2021,* the EPA projects that the use of a combustion turbine with a base load rated heat input of less than or equal to 250 MMBtu/h and with NO_X guarantees of 15 ppm would reduce the efficiency and output by 2 percent relative to a comparable 25 ppm NO_X combustion turbine. As part of this review of the NSPS, the EPA estimated the incremental costs based on the reduced efficiency of these small combustion turbines operating as low, intermediate, or base load units. These costs are determined at annual capacity factors of 5 percent (*i.e.,* low load), 30 percent (*i.e.,* intermediate load), and 60 percent (*i.e.,* base load), respectively, and that NO_X emission rates were reduced from 25 ppm to 15 ppm. Assuming no additional capital or operating costs, the costs of a standard of performance of 15 ppm NO_X for small combustion turbines would be $19,000/ton NO_X, $6,500/ton NO_X, and $5,300/ton NO_X for combustion turbines operating at low, intermediate, and base load levels of utilization, respectively. The Agency is soliciting comment regarding the cost associated with achieving a 15 ppm emissions rate for small stationary combustion turbines firing natural gas, using either dry or wet combustion control technologies. The EPA is also soliciting comment on the capital and O&M costs of dry combustion controls compared to wet combustion controls.

The EPA is not aware of any advances in wet combustion controls that would reduce NO_X emissions when small combustion turbines are using non-natural gas fuels.

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

As discussed in the previous section, due to the potential efficiency loss of a natural gas-fired combustion turbine using dry combustion controls and a guaranteed 15 ppm NO_X emissions rate relative to a combustion turbine guaranteed at 25 ppm NO_X, for each ton of NO_X reduced an additional 70 tons of CO_2 would be emitted. This reduction in efficiency is in the combustion turbine engine, and in this proposal, the Agency is soliciting comment on whether this reduction in efficiency and concomitant increase in CO_2 emissions is less of a concern for combined cycle and CHP combustion turbines because the lost turbine engine efficiency could be partially recovered in the HRSG. If

[41] This turbine model is guaranteed at 100 ppm NO_X using dry combustion controls and 42 ppm using wet combustion controls.

[42] The existing standard for non-natural gas mechanical drive applications is 150 ppm NO_X.

emission rates of other pollutants are unchanged by the lower NO_X combustor, uncontrolled emissions of other criteria and hazardous air pollutants (HAP) could increase by approximately 2 percent.

Wet combustion controls can reduce NO_X emissions by 70 to 80 percent but require highly purified water. However, the water requirements are relatively low compared to other uses of water, and owners/operators in water-constrained areas have the option of using dry combustion controls. The water-to-fuel ratio (WFR) for water or steam injection varies by the type of fuel used and the specific turbine design. The WFR for the NETL aeroderivative combustion turbine is 0.3 kg of water injection per kg of natural gas burned.

In general, in new subpart KKKKa, the EPA proposes to find that the non-air quality health and environmental impacts and energy requirements of both dry and wet combustion controls are acceptable, whether in conjunction with controls capable of meeting a 25 ppm or a 15 ppm NO_X emissions rate when firing natural gas.

v. Promotion, Development, and Implementation of Technology [43]

While dry and wet combustion controls are a mature technology for new and reconstructed stationary combustion turbines, maintaining their use on small combustion turbines with a heat input rating of less than or equal to 250 MMBtu/h will ensure that developers continue to advance the technology for these units.

b. Selective Catalytic Reduction

SCR has been installed and is operating on a number of small stationary combustion turbines, and the technology appears to be readily available for further deployment for highly utilized new and reconstructed combustion turbines with base load rated heat inputs of less than or equal to 250 MMBtu/h. For small natural gas-fired stationary combustion turbines operating in the base load subcategory (*i.e.,* above 40 percent capacity factor on a 12-calendar-month basis), the EPA proposes to include SCR in the determination of the BSER, and proposes an associated emissions standard of 3 ppm NO_X, assuming the SCR is operated in conjunction with combustion controls. For small non-natural gas-fired combustion turbines utilized as base load units, the EPA also proposes to include SCR in the determination of the BSER, and proposes an associated emissions standard of 9 ppm NO_X, again, assuming the SCR is operated in conjunction with combustion controls.

i. Adequately Demonstrated

The EPA is aware of SCR post-combustion control technology being applied to combustion turbines as small as 5 MW and to large combined cycle combustion turbine facilities that are hundreds of megawatts. In addition, SCR has been installed on small reciprocating engines. Therefore, the EPA is proposing that the use of SCR for NO_X control has been adequately demonstrated for all combustion turbines that would be subject to new subpart KKKKa, including new and reconstructed stationary combustion turbines with base load ratings of less than or equal to 250 MMBtu/h of heat input and operating at greater than 40 percent capacity factors.

ii. Extent of Reductions in NO_X Emissions

The percent reduction in NO_X emissions from SCR depends on the level of control initially achieved through combustion controls but is generally greater than 70 percent and can approach 90 percent in certain cases. SCR has been demonstrated to reduce NO_X emission from combustion turbines to approximately 3 ppm. Compared to the NO_X standards for these smaller combustion turbines in subpart KKKK (*i.e.,* as low as 25 ppm), this represents approximately a 90 percent reduction in the emissions standard. However, if combustion controls alone could achieve a 15 ppm NO_X emissions rate, the additional reductions that could be achieved from SCR would be proportionately smaller.

iii. Costs

As discussed in section III.B.7.b, the EPA generally finds that SCR has reasonable costs for stationary combustion turbines of all sizes. For the proposed subcategory of small combustion turbines, the EPA estimated the incremental costs of SCR on a per-ton basis using the current NSPS emissions standard (25 ppm NO_X) in subpart KKKK applicable to natural gas-fired units with base load ratings greater than 50 MMBtu/h of heat input and less than or equal to 850 MMBtu/h and assuming the NO_X is reduced to 3 ppm. In generating specific capital and per-ton cost estimates, the small model plant used by the EPA was a 150 MMBtu/h combustion turbine. For the low and intermediate load cost estimates, the EPA assumed the combustion turbine was operating as a simple cycle turbine and would use hot SCR. For the model base load combustion turbine, the EPA assumed the combustion turbine had a HRSG and would use conventional SCR. The estimated capital cost of the hot SCR is \$3 million, and the estimated capital cost of conventional SCR is \$2 million. The estimated cost effectiveness is \$170,000/ton NO_X, \$31,000/ton NO_X, and \$12,000/ton NO_X for the low, intermediate, and base load small combustion turbines, respectively. The EPA also evaluated the incremental control costs of SCR from a baseline of combustion controls achieving an emissions rate of 15 ppm NO_X. Under this baseline, the estimated cost effectiveness of SCR for small turbines is \$317,000/ton NO_X, \$56,000/ton NO_X, and \$21,000/ton NO_X, respectively.

The EPA proposes that SCR is cost reasonable for natural gas- and non-natural gas-fired stationary combustion turbines with base load ratings of less than or equal to 250 MMBtu/h of heat input and operating as base load units (*i.e.,* at 12-calendar-month capacity factors of greater than 40 percent). However, the EPA recognizes that if it were to conclude that a 15 ppm emissions rate were achievable for natural gas-fired combustion turbines using only combustion controls, then the higher per-ton incremental costs of SCR compared to that baseline may no longer be viewed as cost justified. The EPA also recognizes that per-ton cost estimates would likely be proportionately higher as the size of combustion turbines diminishes from the 150 MMBtu/h model plant used in this analysis. The EPA requests comment on the cost factor for SCR on small turbines, including in relation to the following topics: whether, reviewing all of the relevant cost considerations (as discussed in section III.B.7.b), SCR is cost reasonable even at lower operating loads than base load; whether SCR would no longer be incrementally cost reasonable against a 15 ppm baseline emissions rate; whether SCR may not be cost reasonable for turbines smaller than 150 MMBtu/h, such as when cost factors, including capital and operating costs, are analyzed for turbines smaller than 100 or 50 MMBtu/h.

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

Post-combustion SCR uses ammonia as a reagent, and some ammonia is emitted either by passing through the catalyst bed without reacting with NO_X (unreacted ammonia) or passing around

[43] Under longstanding precedent, the EPA has considered this factor under CAA section 111, but even if this factor were not considered, it would not affect our proposed determinations of the BSER in this action.

the catalyst bed through leaks in the seals. Both of these types of excess ammonia emissions are referred to as ammonia slip. Ammonia is a precursor to the formation of fine particulate matter (*i.e.,* $PM_{2.5}$). Ammonia slip increases as catalyst beds age and is often limited to 10 ppm or less in operating permits. Ammonia catalysts are available to reduce emissions of ammonia. The ammonia catalyst consists of an additional catalyst bed after the SCR catalyst that reacts with the ammonia that passes through and around the catalyst to reduce overall ammonia slip. In the NETL model plants used in the EPA's analysis, no additional ammonia catalyst was included, and ammonia emissions were limited to 10 ppm at the end of the catalyst's service life. For estimating secondary impacts, the EPA assumed average ammonia emissions of 3.5 ppm. Since the ammonia slip is assumed to be 3.5 ppm regardless of the NO_X emissions rate prior to the SCR, the amount of ammonia emitted per ton of NO_X controlled increases with combustion controls that achieve lower emission rates prior to the SCR. Assuming the emissions rate is decreased from the manufacturer guaranteed emission rates to an emissions rate of 3 ppm NO_X, the EPA estimates that for each ton of NO_X controlled, 0.06 tons, 0.1 tons, and 0.2 tons of ammonia are emitted from SCR controls on combustion turbines with guaranteed NO_X emission rates of 25 ppm, 15 ppm, and 9 ppm, respectively. For combustion turbines with base load ratings of less than or equal to 250 MMBtu/h of heat input, the EPA used a 25 ppm NO_X baseline and 0.06 tons of ammonia per ton of NO_X reduced.

SCR also reduces the efficiency of a combustion turbine through the auxiliary/parasitic load requirements to run the SCR and the backpressure created from the catalyst bed. The EPA used the NETL values to approximate auxiliary load requirements and assumed the backpressure reduced gross output by 0.3 percent. Similar to ammonia, the CO_2 per ton of NO_X reduced depends on the amount of NO_X entering the SCR. The EPA estimates that for each ton of NO_X controlled, 5 tons, 8 tons, and 16 tons of CO_2 are emitted as a result of the SCR on combustion turbines with guaranteed NO_X emission rates of 25 ppm, 15 ppm, and 9 ppm, respectively. For stationary combustion turbines with base load ratings of less than or equal to 250 MMBtu/h of heat input, the EPA used a 25 ppm NO_X baseline and 5 tons of CO_2 per ton of NO_X reduced.

The EPA is proposing in new subpart KKKKa that the non-air quality health and environmental impacts and energy requirements of SCR are acceptable for stationary combustion turbines with base load ratings of less than or equal to 250 MMBtu/h of heat input. SCR technologies have improved in recent years to reduce these impacts, and the widespread deployment of SCR on combustion turbines of all sizes, at least in the power sector the last 5 years, indicates that States and permitting authorities have found these impacts sufficiently manageable that SCR has been mandated for NO_X reductions in spite of these modest effects on other pollutants and associated energy requirements.

v. Promotion, Development, and Implementation of Technology

Installations of SCR help reduce capital and operating costs through learning by doing. As SCR becomes more affordable, it can be installed on additional combustion turbines. SCR is applicable to multiple industries, and advancement for combustion turbines can be transferred to these industries.

10. BSER for Medium Combustion Turbines

This section describes the proposed BSER for new and reconstructed medium combustion turbines with base load ratings of greater than 250 MMBtu/h of heat input and less than or equal to 850 MMBtu/h. For combustion turbines in this medium subcategory, the proposed BSER is the use of combustion controls with the addition of post-combustion SCR for intermediate and base load combustion turbines (*i.e.,* those with annual capacity factors greater than 20 percent) and dry or wet combustion controls for low load combustion turbines (*i.e.,* those with annual capacity factors less than or equal to 20 percent) depending on whether natural gas or non-natural gas fuels are being fired.

a. Combustion Controls

This section describes the current availability and performance of dry and wet combustion controls used by owners/operators of medium stationary gas and combustion turbines to limit NO_X emissions. In 2006, these combustion controls were maintained as the BSER in existing subpart KKKK, and this technology continues to be used on new and reconstructed stationary combustion turbines, including those with base load ratings of greater than 250 MMBtu/h of heat input and less than or equal to 850 MMBtu/h.

i. Adequately Demonstrated

Dry and/or wet combustion controls are widely available from major manufacturers for combustion turbines with base load ratings of greater than 250 MMBtu/h of heat input and less than or equal to 850 MMBtu/h. Combustion controls are mature technologies that have been demonstrated for multiple years in various end-use applications, and the EPA proposes to maintain in new subpart KKKKa that combustion controls are adequately demonstrated for this subcategory. Both dry and wet combustion controls have been demonstrated on combustion turbines burning gaseous fuels. However, for liquid fuels such as distillates, dry combustion controls are less effective and only wet combustion controls are proposed to be the BSER.

ii. Extent of Reductions in NO_X Emissions

Manufacturer NO_X emission rate performance guarantees for medium natural gas-fired stationary combustion turbines using dry combustion controls range from 15 ppm to 25 ppm. For example, most high-efficiency aeroderivative combustion turbines have NO_X emission rate performance guarantees of 25 ppm while for most natural gas-fired frame units using dry combustion controls, the guaranteed NO_X emissions rate is 15 ppm. However, there is some variability among frame units and certain designs have guaranteed emissions rates of 25 ppm. Dry combustion controls on some medium natural gas-fired combustion turbines appear to be capable of meeting emissions rates as low as 9 ppm in certain applications. Like the subcategory for small combustion turbines, the EPA is soliciting comment in this proposal on whether wet combustion controls, particularly steam injection, can achieve a 15 ppm or lower NO_X emission rate when gaseous fuels are used; if not, then the EPA also requests comment on whether wet combustion controls should continue to be considered a BSER technology on which emissions standards are based, at least for medium combustion turbines using natural gas.

The EPA is not aware of any advances in wet combustion controls that would reduce NO_X emissions when medium combustion turbines are using non-natural gas fuels.

iii. Costs

The use of dry combustion controls that can achieve 25 ppm NO_X has been standard equipment for natural gas-fired stationary combustion turbines sold nationwide for multiple years, and combustion controls consistent with the existing standards in subpart KKKK represent little costs to the regulated community. Like the subcategory for small combustion turbines, at this time, the Agency does not have capital or O&M cost information for medium combustion turbines with NO_X emission rate guarantees of 15 ppm relative to the costs of comparable combustion turbines with 25 ppm NO_X guarantees. Therefore, in this proposal, the EPA solicits comment and information on such capital and O&M costs. To the extent the Agency receives information that the costs of dry combustion controls with NO_X emission rates of 15 ppm are reasonable, the Agency may finalize NO_X emission standards for natural gas-fired medium combustion turbines operating at low loads (*i.e.,* at 12-calendar-month capacity factors of less than or equal to 20 percent) consistent with these guaranteed performance levels. As discussed further in this section, for medium stationary combustion turbines operating at intermediate and base loads (*i.e.,* at 12-calendar-month capacity factors of greater than 20 percent), this question would not be relevant for the rule as proposed, since those units would also be subject to an emissions standard based on application of SCR. The EPA also is soliciting additional information on potential impacts of low NO_X combustors on the operation of medium combustion turbines. In particular, the Agency is seeking information on potential reductions in efficiency and/or output of medium combustion turbines using combustion controls that are capable of achieving 15 ppm NO_X or less.

Based on analysis like that performed for small combustion turbines, the EPA projects that the use of a stationary combustion turbine with NO_X guarantees of 15 ppm would reduce the efficiency and output relative to a comparable 25 ppm NO_X combustion turbine by 2 percent.

The EPA estimates the incremental costs based on the reduced efficiency of low, intermediate, and base load medium combustion turbines. These costs are determined at annual capacity factors of 5 percent, 30 percent, and 60 percent, respectively, and using a 486 MMBtu/h model plant. Assuming no additional capital or operating costs, the costs of a NO_X standard of 15 ppm for medium combustion turbines would be \$19,000/ton NO_X, \$6,500/ton NO_X, and \$5,300/ton NO_X, respectively, for low, intermediate, and base load combustion turbines.

The EPA is also soliciting comment on the capital and O&M costs of dry combustion controls compared to wet combustion controls.

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

As discussed in the previous section, due to the potential efficiency loss of a natural gas-fired combustion turbine using dry combustion controls and a guaranteed 15 ppm NO_X emissions rate relative to a combustion turbine guaranteed at 25 ppm NO_X, for each ton of NO_X reduced an additional 70 tons of CO_2 would be emitted. This reduction in efficiency is in the combustion turbine engine, and in this proposal, the Agency is soliciting comment on whether this reduction in efficiency and concomitant increase in CO_2 emissions is less of a concern for combined cycle and CHP combustion turbines because the lost turbine engine efficiency could be partially recovered in the HRSG. If emission rates of other pollutants are unchanged by the lower NO_X combustor, uncontrolled emissions of other criteria and hazardous air pollutants (HAP) could increase by approximately 2 percent.

Wet combustion controls can reduce NO_X emissions by 70 to 80 percent but require highly purified water.[44] However, the water requirements are relatively low compared to other uses of water, and owners/operators in water-constrained areas have the option of using dry combustion controls. The water-to-fuel ratio (WFR) for water or steam injection varies by the type of fuel used and the specific turbine design.

In general, in new subpart KKKKa, the EPA proposes to find that the non-air quality health and environmental impacts and energy requirements of both dry and wet combustion controls are acceptable, whether in conjunction with controls capable of meeting a 25 ppm or a 15 ppm NO_X emissions rate when firing natural gas.

v. Promotion, Development, and Implementation of Technology

While combustion controls are a mature technology for new combustion turbines, requiring their use on medium combustion turbines will ensure that developers continue to advance the technology for these units.

b. Selective Catalytic Reduction

The EPA is proposing that SCR in combination with combustion controls is the BSER for new and reconstructed stationary combustion turbines with base load ratings of greater than 250 MMBtu/h of heat input and less than or equal to 850 MMBtu/h and that will be utilized as intermediate or base load units with 12-calendar-month capacity factors of greater than 20 percent.

As discussed in the previous section for small base load combustion turbines, SCR has been installed and is currently operating on many sizes and designs of stationary combustion turbines, and the technology appears to be readily available for further deployment for medium combustion turbines operating at intermediate and base load capacity factors. Based on the application of combustion controls with SCR, in new subpart KKKKa, the EPA is proposing an associated emissions standard of 3 ppm NO_X for natural gas-fired units. For medium non-natural gas-fired combustion turbines utilized as intermediate or base load units, the EPA also proposes to include SCR with combustion controls in the determination of the BSER, and proposes an associated emissions standard of 9 ppm NO_X, assuming the SCR is operated in conjunction with combustion controls.

i. Adequately Demonstrated

The EPA is aware of SCR post-combustion control technology being applied to combustion turbines as small as 5 MW and to large combined cycle combustion turbine facilities that are hundreds of megawatts. In addition, SCR has been installed on reciprocating engines. Therefore, the EPA is proposing that the use of SCR for NO_X control has been adequately demonstrated for all combustion turbines that would be subject to new subpart KKKKa, including new and reconstructed stationary combustion turbines with base load ratings of greater than 250 MMBtu/h of heat input and less than or equal to 850 MMBtu/h and operating at greater than a 20 percent capacity factor.

ii. Extent of Reductions in NO_X Emissions

The percent reduction in NO_X emissions from SCR depends on the level of control achieved through combustion controls but is generally greater than 70 percent and can approach 90 percent in certain cases. In conjunction with dry combustion controls on medium natural gas-fired combustion turbines, SCR has been demonstrated to reduce NO_X emissions to approximately 3 ppm compared to 25 ppm with just dry combustion controls. This represents almost a 90 percent

[44] U.S. Environmental Protection Agency (EPA). (April 2002). Appendix B.17: Water or Steam Injection Review Draft. Available at *https://www3.epa.gov/ttnchie1/mkb/documents/B_17a.pdf.*

reduction in NO_X emissions. The current NO_X standard in subpart KKKK for combustion turbines of this size firing non-natural gas fuels is 74 ppm. This standard is based on the application of wet combustion controls alone. In new subpart KKKKa, based upon application of SCR in combination with combustion controls, the EPA is proposing a NO_X emission standard of 9 ppm for medium combustion turbines utilized as intermediate or base load units and firing non-natural gas fuels. This proposed standard represents approximately a 90 percent reduction compared to the current standard of 74 ppm.

iii. Costs

The EPA estimated the incremental costs of SCR on a per-ton basis using the current NSPS emissions standard for this subcategory (a baseline of 25 ppm NO_X) and assuming emissions are reduced to 3 ppm NO_X. The medium model plant used by the EPA was a 486 MMBtu/h stationary combustion turbine. For the low and intermediate load cost estimates, the EPA assumed the combustion turbine was operating as a simple cycle turbine and would use hot SCR. For the model base load cost estimates, the EPA assumed the combustion turbine had a HRSG and would use conventional SCR. The estimated capital cost of the hot SCR is $3.6 million, and the estimated capital cost of conventional SCR is $2.4 million. The estimated cost effectiveness is $62,000/ton NO_X, $12,000/ton NO_X, and $5,100/ton NO_X for low, intermediate, and base load medium combustion turbines, respectively, compared to the baseline emissions rate of 25 ppm in current subpart KKKK. The EPA also evaluated the incremental control costs as compared to combustion controls achieving an emissions rate of 15 ppm NO_X. Under this alternative baseline, the estimated cost effectiveness is $110,000/ton NO_X, $22,000/ton NO_X, and $8,700/ton NO_X for low, intermediate, and base load medium combustion turbines, respectively.

The EPA proposes that the costs of SCR are reasonable for new and reconstructed medium size intermediate load or base load combustion turbines firing natural gas or non-natural gas fuels. The EPA recognizes that if it were to conclude that a 15 ppm emissions rate were achievable for these medium turbines using only combustion controls, then the per-ton incremental cost of SCR against that baseline would increase to $22,000/ton. Nonetheless, in reviewing all of the relevant cost considerations (as discussed in section III.B.7.b), the EPA does not find this result so high as to render SCR as applied in this instance no longer capable of being considered the BSER. The EPA requests comment on the cost factor for SCR on medium-sized stationary combustion turbines.

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

Post-combustion SCR uses ammonia as a reagent, and some ammonia is emitted either by passing through the catalyst bed without reacting with NO_X (unreacted ammonia) or passing around the catalyst bed through leaks in the seals. Both of these types of excess ammonia emissions are referred to as ammonia slip. Ammonia is a precursor to the formation of fine particulate matter (*i.e.,* $PM_{2.5}$). Ammonia slip increases as catalyst beds age and is often limited to 10 ppm or less in operating permits. Ammonia catalysts are available to reduce emissions of ammonia. The ammonia catalyst consists of an additional catalyst bed after the SCR catalyst that reacts with the ammonia that passes through and around the catalyst to reduce overall ammonia slip. In the NETL model plants used in the EPA's analysis, no additional ammonia catalyst was included, and ammonia emissions were limited to 10 ppm at the end of the catalyst's service life. For estimating secondary impacts, the EPA assumed average ammonia emissions of 3.5 ppm. Since the ammonia slip is assumed to be 3.5 ppm regardless of the NO_X emissions rate prior to the SCR, the amount of ammonia emitted per ton of NO_X controlled increases with combustion controls that achieve lower emission rates prior to the SCR. Assuming the emissions rate is decreased from the manufacturer guaranteed emission rates to an emissions rate of 3 ppm NO_X, the EPA estimates that for each ton of NO_X controlled, 0.06 tons of ammonia are emitted from SCR controls on combustion turbines with base load ratings of greater than 250 MMBtu/h of heat input and less than or equal to 850 MMBtu/h and with guaranteed NO_X emission rates of 25 ppm.

SCR also reduces the efficiency of a combustion turbine through the auxiliary/parasitic load requirements to run the SCR and the backpressure created from the catalyst bed. The EPA used the NETL values to approximate auxiliary load requirements and assumed the backpressure reduced gross output by 0.3 percent. Similar to ammonia, the CO_2 per ton of NO_X reduced depends on the amount of NO_X entering the SCR. The EPA estimates that for each ton of NO_X controlled, 5 tons of CO_2 are emitted as a result of the SCR on combustion turbines with base load ratings of greater than 250 MMBtu/h of heat input and less than or equal to 850 MMBtu/h with guaranteed NO_X emission rates of 25 ppm.

The EPA is proposing in new subpart KKKKa that the non-air quality health and environmental impacts and energy requirements of SCR are acceptable for stationary combustion turbines with base load ratings of greater than 250 MMBtu/h of heat input and less than or equal to 850 MMBtu/h and that operate at intermediate or base load capacity factors. SCR technologies have improved in recent years to reduce these impacts, and the widespread deployment of SCR on combustion turbines of all sizes, at least going back in the power sector the last 5 years, indicates that States and permitting authorities have found these impacts sufficiently manageable that SCR has been mandated for NO_X reductions in spite of these modest effects on other pollutants and associated energy requirements.

v. Promotion and Development and Implementation of Technology

Installations of SCR help reduce capital and operating costs through learning by doing. As SCR becomes more affordable it can be installed on additional stationary combustion turbines. SCR is applicable to multiple industries, and advancement for combustion turbines can be transferred to these industries.

11. BSER for Large Combustion Turbines

This section describes the proposed BSER for new, modified, and reconstructed stationary combustion turbines in new subpart KKKKa with base load ratings of greater than 850 MMBtu/h of heat input. Like the subcategories of small and medium combustion turbines, the EPA is proposing to further subdivide large combustion turbines according to whether they will be utilized as low, intermediate, or base load units. The proposed BSER and corresponding NO_X emission standards will also depend on whether these turbines burn natural gas or non-natural gas fuels. For large combustion turbines in this subcategory, the proposed BSER is the use of SCR in combination with combustion controls for intermediate and base load units (*i.e.,* those with 12-calendar-month capacity factors greater than 20 percent). For large combustion turbines that will be utilized as low load units (*i.e.,* at 12-

calendar-month capacity factors of less than or equal to 20 percent), the proposed BSER is the use of dry combustion controls for combustion turbines firing natural gas and wet combustion controls for combustion turbines firing non-natural gas fuels.

a. Combustion Controls

This section describes the availability of combustion controls used by owners/operators of large stationary combustion turbines. Dry combustion controls, such as lean premix/DLN, are mature technologies that were determined to be the BSER in existing subpart KKKK and continue to be used as NO_X emission controls on new natural gas-fired stationary combustion turbines. Wet combustion controls were not part of the BSER for large natural gas-fired combustion turbines in subpart KKKK because the technology had not demonstrated the ability to achieve a NO_X emissions rate of 15 ppm—the limit set in subpart KKKK for new, modified, and reconstructed large natural gas-fired combustion turbines based on dry combustion controls.

i. Adequately Demonstrated

Dry combustion controls are widely available from major manufacturers of large aeroderivative and frame type stationary combustion turbines that burn natural gas. Combustion controls are mature technologies and have been demonstrated for multiple years in various end-use applications, and in new subpart KKKKa, the EPA is proposing to maintain that dry combustion controls are adequately demonstrated for new, modified, and reconstructed natural gas-fired turbines in this large subcategory. For new, modified, and reconstructed large turbines that burn non-natural gas fuels, the EPA is proposing to maintain that wet combustion controls are adequately demonstrated for control of NO_X emissions.

ii. Extent of Reductions in NO_X Emissions

Manufacturer NO_X emission rate performance guarantees for large natural gas-fired stationary combustion turbines using dry combustion controls are primarily 9 ppm and 25 ppm, respectively. New aeroderivative and high-efficiency frame units are currently guaranteed at 25 ppm NO_X while less efficient frame units have guaranteed NO_X emission rates of 9 ppm or 15 ppm, and, in certain applications, 5 ppm. Even considering the potential reduction in efficiency, a 9 ppm NO_X combustion turbine emits approximately 40 percent less NO_X than a 15 ppm NO_X combustion turbine.

The EPA is not aware of any advances in combustion controls for non-natural gas-fired fuels. Therefore, in new subpart KKKKa, the EPA is proposing to maintain that wet combustion controls (*i.e.,* water or steam injection) are the BSER for new, modified, and reconstructed large stationary combustion turbines that burn non-natural gas fuels and that operate at low loads. As discussed below in section III.B.12, the EPA also is proposing to maintain from subpart KKKK an associated emissions rate of 42 ppm NO_X for this subcategory of large turbines.

iii. Costs

The use of combustion controls able to achieve 15 ppm NOx or less has been standard equipment for combustion turbines sold in the United States for multiple years, and combustion controls consistent with the existing standards in subpart KKKK represent little cost to the regulated community. When subpart KKKK was finalized in 2006, the largest aeroderivative combustion turbine available at the time had a base load rating of less than 850 MMBtu/h of heat input. However, less-efficient frame units greater than 850 MMBtu/h were available with guaranteed NO_X emission rates of 15 ppm or less. Since subpart KKKK was finalized in 2006, several aeroderivative combustion turbines greater than 850 MMBtu/h have been developed and large frame turbines have increased efficiency, and as a consequence, most guaranteed NO_X emission rates have increased to 25 ppm. These large aeroderivative and high-efficiency frame combustion turbines, even when operating at lower capacity factors, could only comply with the current standards in subpart KKKK by installing SCR. Therefore, in new proposed subpart KKKKa, SCR costs are included in the baseline level of control for these units at all loads. The EPA is soliciting comment on whether combustion controls are being developed for the high-efficiency machines currently guaranteed at 25 ppm NO_X that would reduce the guaranteed NO_X emissions rate.

At this time, the Agency does not have detailed capital or O&M cost information and is soliciting comment on the costs of combustion turbines with NO_X guarantees of 9 ppm and/or 5 ppm relative to the costs of comparable combustion turbines with 15 ppm or 25 ppm guarantees. To the extent the Agency receives information that the costs of combustion controls with emission rates of 9 ppm or 5 ppm are reasonable, the Agency could finalize emission standards consistent with these guaranteed levels (at least in that subcategory where the EPA has not also proposed SCR as part of the BSER). The EPA is also soliciting additional information on potential impacts of low NO_X combustors on the operation of combustion turbines. In particular, the Agency is seeking information on potential reductions in efficiency and/or output of combustion controls that are capable of achieving 9 ppm and/or 5 ppm NO_X or less.

Based on design information in *Gas Turbine World 2021,* the EPA projected that the use of a combustion turbine with NO_X guarantees of 9 ppm would reduce the efficiency and output relative to a comparable 15 ppm NOx combustion turbine by 2 percent. The EPA estimated the incremental costs of a BSER based on the use of DLN guaranteed at 9 ppm NO_X based on the reduced efficiency of low, intermediate, and base load combustion turbines. These costs were determined at annual capacity factors of 5 percent, 30 percent, and 60 percent, respectively. Assuming no additional capital or operating costs, the costs of achieving a rate of 9 ppm using only combustion controls for large combustion turbines would be $22,000/ton NO_X, $9,300/ton NO_X, and $8,000/ton NO_X for low, intermediate, and base load combustion turbines, respectively. The Agency is soliciting comment on the costs and other impacts of low NO_X dry combustion controls, particularly as associated with achieving an emissions rate of 9 ppm.

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

Due to the potential efficiency loss of a combustion turbine guaranteed at 9 ppm NO_X, relative to one guaranteed at 15 ppm NO_X, for each ton of NO_X reduced an additional 110 tons of CO_2 would be emitted. This reduction in efficiency is in the combustion turbine engine, and the Agency is soliciting comment on whether this reduction in efficiency is less important to combined cycle and CHP combustion turbines because the lost turbine engine efficiency could be partially recovered in the HRSG. If emission rates of other pollutants are unchanged by the low NO_X combustor, emissions of other criteria and hazardous air pollutants (HAP) would increase by approximately 2 percent.

In general, the EPA proposes to find that the non-air quality health and environmental impacts and energy requirements of both dry and wet combustion controls are acceptable, whether in conjunction with controls capable of meeting a 25 ppm or a 15 ppm emissions rate when firing natural gas.

v. Promotion, Development, and Implementation of Technology

While combustion controls are a mature technology for stationary combustion turbines, requiring their use on new, modified, and reconstructed combustion turbines of greater than 850 MMBtu/h will ensure that developers continue to advance the technology for these units.

b. Selective Catalytic Reduction

The EPA is proposing in new subpart KKKKa that the costs of SCR are reasonable on a nationwide basis for new, modified, and reconstructed stationary combustion turbines with base load ratings of greater than 850 MMBtu/h of heat input and utilized as intermediate and base load units. However, for large stationary combustion turbines that will be utilized at low loads, the EPA is proposing in new subpart KKKKa that the costs of SCR are not reasonable.

i. Adequately Demonstrated

The EPA is aware of SCR post-combustion control technology being applied to combustion turbines as small as 5 MW and to large combined cycle combustion turbine facilities that are hundreds of megawatts. In addition, SCR has been installed on reciprocating engines. Therefore, the EPA is proposing that the use of SCR for NO_X control has been adequately demonstrated for all combustion turbines that would be subject to new subpart KKKKa, including new, modified, and reconstructed stationary combustion turbines with base load ratings of greater than 850 MMBtu/h of heat input and operating at greater than a 20 percent capacity factor.

ii. Extent of Reductions in NO_X Emissions

The percent reduction in NO_X emissions from SCR depends on the level of control achieved through combustion controls but is generally greater than 70 percent and can approach 90 percent in certain cases. In conjunction with dry combustion controls on large natural gas-fired combustion turbines, SCR has been demonstrated to reduce NO_X emissions to approximately 3 ppm compared to 15 ppm with just dry combustion controls. This represents an 80 percent reduction in NO_X emissions. The NO_X standard in existing subpart KKKK for combustion turbines of this size firing non-natural gas fuels is 42 ppm. This standard is based on the application of wet combustion controls. In new subpart KKKKa, based upon application of SCR in combination with combustion controls, the EPA is proposing a NO_X emission standard of 9 ppm for new, modified, and reconstructed large combustion turbines utilized as intermediate or base load units and firing non-natural gas fuels. This proposed standard represents approximately an 80 percent reduction compared to the current standard of 42 ppm.

iii. Costs

The EPA estimated the incremental costs of SCR on a per-ton basis using the current NSPS emissions standard (15 ppm NO_X) in subpart KKKK and assuming the NO_X is reduced to 3 ppm. The large model plant used by the EPA was a 4,450 MMBtu/h combustion turbine. For the low and intermediate load cost estimates, the EPA assumed the combustion turbine was operating as a simple cycle turbine and would use hot SCR. For the model base load combustion turbine, the EPA assumed the combustion turbine had a HRSG and would use conventional SCR. The estimated capital cost of the hot SCR is $10 million and the estimated capital cost of conventional SCR is $6 million. The estimated cost effectiveness is $33,000/ton NO_X, $8,400/ton NO_X, and $3,800/ton NO_X for low, intermediate, and base load combustion turbines, respectively. In the event the EPA were to conclude that combustion controls alone could achieve emissions rates of 9 ppm or 5 ppm, the EPA also evaluated the incremental control costs based on combustion controls achieving an emissions rate of 3 ppm NO_X. Under this baseline, the estimated cost effectiveness is $65,000/ton NO_X, $16,000/ton NO_X, and $6,400/ton NO_X for low, intermediate, and base load turbines in the 9 ppm baseline cases, respectively, and $190,000/ton NO_X, $42,000/ton NO_X, and $16,000/ton NO_X for the low, intermediate, and base load turbines in the 5 ppm baseline cases, respectively. For the reasons discussed in section III.B.7.b, the EPA proposes that SCR is cost-reasonable for intermediate and base load large combustion turbines.

The EPA recognizes that if it were to conclude that a 9 ppm or a 5 ppm NO_X emissions rate were achievable for large natural gas-fired turbines using only dry combustion controls, then the per-ton incremental cost of SCR against that baseline would increase as described. Nonetheless, in reviewing all of the relevant cost considerations (as discussed in section III.B.7.b), the EPA does not find the resulting cost figures so exorbitantly high that it renders SCR as applied in those instances no longer capable of being considered the BSER—with the potential exception of the incremental cost associated with a 5 ppm baseline in the intermediate load subcategory. The EPA requests comment on the cost factor for SCR on large-sized turbines.

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

Post-combustion SCR uses ammonia as a reagent, and some ammonia is emitted either by passing through the catalyst bed without reacting with NO_X (unreacted ammonia) or passing around the catalyst bed through leaks in the seals. Both of these types of excess ammonia emissions are referred to as ammonia slip. Ammonia is a precursor to the formation of fine particulate matter (*i.e.,* $PM_{2.5}$). Ammonia slip increases as catalyst beds age and is often limited to 10 ppm or less in operating permits. Ammonia catalysts are available to reduce emissions of ammonia. The ammonia catalyst consists of an additional catalyst bed after the SCR catalyst that reacts with the ammonia that passes through and around the catalyst to reduce overall ammonia slip. In the NETL model plants used in the EPA's analysis, no additional ammonia catalyst was included, and ammonia emissions were limited to 10 ppm at the end of the catalyst's service life. For estimating secondary impacts, the EPA assumed average ammonia emissions of 3.5 ppm. Since the ammonia slip is assumed to be 3.5 ppm regardless of the NO_X emissions rate prior to the SCR, the amount of ammonia emitted per ton of NO_X controlled increases with combustion controls that achieve lower emission rates prior to the SCR. Assuming the emissions rate is decreased from the manufacturer guaranteed emission rates to an emissions rate of 3 ppm NO_X, the EPA estimates that for each ton of NO_X controlled, 0.1 tons of ammonia are emitted from SCR controls on combustion turbines with base load ratings of greater than 850 MMBtu/h of heat input and with guaranteed NO_X emission rates of 15 ppm.

SCR also reduces the efficiency of a combustion turbine through the auxiliary/parasitic load requirements to run the SCR and the backpressure created from the catalyst bed. The EPA used the NETL values to approximate auxiliary load requirements and assumed the backpressure reduced gross output by 0.3 percent. Similar to ammonia, the CO_2 per ton of NO_X reduced depends on the amount of NO_X entering the SCR. The EPA estimates that for each ton of NO_X controlled, 8 tons of CO_2 are emitted as a result of the SCR on combustion turbines with base load ratings of greater than 850 MMBtu/h of heat input with guaranteed NO_X emission rates of 15 ppm.

The EPA is proposing in new subpart KKKKa that the non-air quality health and environmental impacts and energy requirements of SCR are acceptable for stationary combustion turbines with base load ratings of greater than 850 MMBtu/h of heat input and that operate at intermediate or base load capacity factors. SCR technologies have improved in recent years to reduce these impacts, and the widespread deployment of SCR on combustion turbines of all sizes, at least in the power sector the last 5 years, indicates that States and permitting authorities have found these impacts sufficiently manageable that SCR has been mandated for NO_X reductions in spite of these modest effects on other pollutants and associated energy requirements.

v. Promotion and Development and Implementation of Technology

Installations of SCR help reduce capital and operating costs through learning by doing. As SCR becomes more affordable it can be installed on additional combustion turbines. SCR is applicable to multiple industries, and advancement for combustion turbines can be transferred to these industries.

12. Proposed NO_X Emissions Standards for New and Reconstructed Stationary Combustion Turbines in 40 CFR Part 60, Subpart KKKKa

This section describes the proposed emissions standards, based on the identified BSER, for each of the proposed subcategories of new and reconstructed stationary combustion turbines in new subpart KKKKa. The EPA used two primary sources of information for the proposed emission standards—combustion turbine manufacturer guaranteed NO_X emission rates and hourly emissions database information reported to the EPA and available from CAMPD. The EPA considered, but did not use, permitted emission rates because the numeric standards differ in terms of the averaging period used for compliance purposes and under what operating conditions the standards are applicable. Similarly, the EPA is not proposing to base the proposed emission standards on stack performance test information because these emission rates are representative of what can be achieved under the conditions of a performance test and do not necessarily represent what is achievable under other operating conditions. The EPA is proposing that manufacturer guarantees represent appropriate NO_X emission standards for determination of the BSER based on the use combustion controls. The EPA is also proposing that the analysis of hourly emissions data allows the Agency to evaluate the appropriate numeric standards of the BSER based on the use of post-combustion SCR in combination with combustion controls while also identifying under what conditions the emission standards are applicable.

a. Emissions Standards for Small Combustion Turbines

The NO_X standards in subpart KKKK for small natural gas-fired stationary combustion turbines range from 100 ppm for mechanical drive applications with base load ratings of less than or equal to 50 MMBtu/h [45] of heat input to 25 ppm for certain combustion turbines with base load ratings of greater than 50 MMBtu/h of heat input and less than or equal to 850 MMBtu/h. The current NO_X standards in subpart KKKK for small non-natural gas-fired stationary combustion turbines range from 150 ppm for mechanical drive applications with base load ratings of less than or equal to 50 MMBtu/h [46] of heat input to 74 ppm for certain combustion turbines with base load ratings of greater than 50 MMBtu/h of heat input and less than or equal to 850 MMBtu/h.

As discussed in section III.B.9, in new subpart KKKKa, the proposed BSER for the subcategory of small stationary combustion turbines with base load ratings of less than or equal to 250 MMBtu/h of heat input is SCR in combination with combustion controls when operating as a base load unit. The proposed BSER is combustion controls alone when operating as a low or intermediate load unit. The EPA is proposing in new subpart KKKKa an emissions rate of 3 ppm NO_X for these small base load units and 25 ppm NO_X for low and intermediate load small turbines firing natural gas. The EPA solicits comment on whether small units burning natural gas can achieve a 15 ppm or 9 ppm NO_X emissions rate using combustion controls alone.

[45] The NO_X emissions standard in subpart KKKK for natural gas-fired electric generating combustion turbines with base load ratings of less than or equal to 50 MMBtu/h is 42 ppm.

[46] The NO_X emissions standard in subpart KKKK for non-natural gas-fired electric generating combustion turbines with base load ratings of less than or equal to 50 MMBtu/h is 96 ppm.

Also, in new subpart KKKKa, the proposed BSER for small combustion turbines is SCR in combination with combustion controls when operating as a base load unit and firing non-natural gas fuels and is wet combustion controls alone when operating as a low or intermediate load unit and firing non-natural gas fuels. The EPA is proposing in new subpart KKKKa an emissions rate of 9 ppm NO_X for these small base load combustion turbines and is proposing to maintain an emissions rate of 74 ppm NO_X for low and intermediate load small turbines firing non-natural gas. The EPA is proposing to maintain the NO_X emission standards for small non-natural gas-fired combustion turbines operating as intermediate or low load units because the EPA is not aware of any improvements in the performance of wet combustion controls for these combustion turbines. Please refer to Table 1 for the remaining proposed emissions standards.

b. Emissions Standards for Medium Combustion Turbines

The EPA is proposing in new subpart KKKKa to create a medium size-based subcategory for stationary combustion turbines with base load ratings of greater than 250 MMBtu/h of heat input and less than or equal to 850 MMBtu/h. Within this subcategory, the EPA is proposing to further divide these combustion turbines into low, intermediate, and base load units and according to whether they burn natural gas or non-natural gas fuels. See the discussion in section III.B.4. Also, as discussed in section III.B.7, the EPA is proposing in new subpart KKKKa that the BSER for medium natural gas-fired combustion turbines utilized as intermediate and base load units (*i.e.,* at 12-calendar-month capacity factors of greater than 20 percent) is combustion controls in combination with SCR. For medium combustion turbines firing natural gas and utilized as low load units (*i.e.,* at 12-calendar-month capacity factors of less than or equal to 20 percent), the EPA is proposing that the BSER is combustion controls alone. The proposed NO_X emissions standard for intermediate and base load medium-sized combustion turbines firing natural gas is 3 ppm while the proposed NO_X emissions standard for low load medium-sized combustion turbines is 25 ppm. Please refer to Table 1 for the remaining proposed emissions standards.

i. Low Load Medium Combustion Turbines

The current NO_X standards in subpart KKKK for medium natural gas-fired combustion turbines is 25 ppm. For this proposed action, the EPA reviewed hourly emissions data from two medium aeroderivative simple cycle facilities without SCR that recently commenced operation. The proposed 25 ppm NO_X emissions rate is consistent with the 99.7 percent confidence interval of the 4-hour rolling emissions rate at higher loads.[47] The combustion turbines at these facilities were able to maintain their emissions rate until hourly loads of approximately 70 percent were reached. However, as discussed in relation to small turbines in section III.B.9, the EPA requests comment on whether a NO_X emissions rate as low as 15 ppm might be achievable based on combustion controls alone for medium combustion turbines operating at low capacity factors on an annual basis. The EPA also requests comment on whether SCR should be an appropriate component of the BSER for medium combustion turbines operating at low capacity factors, and if so, whether 3 ppm would be an appropriate NO_X emissions rate that low-load sources can achieve.

The NO_X standard in subpart KKKK for medium non-natural gas-fired combustion turbines is 74 ppm. Manufacturer guarantees for fuels other than natural gas are more limited, but reported values range between 42 ppm and 58 ppm. While the EPA is proposing to maintain the same non-natural gas standard for low capacity factors as in existing subpart KKKK, the EPA is soliciting comment on the achievable emission rates of medium combustion turbines when combusting distillate oil and other non-natural gas fuels. The EPA is particularly interested in emissions rates achievable using dry and/or wet combustion controls. The Agency also is soliciting comment on the costs of including wet combustion controls on combustion turbines that only operate on distillate oil or other non-natural gas fuels during natural gas curtailments or other infrequent events. To the extent the control costs are significantly higher for owners/operators of these units relative to costs for owners/operators that already use demineralized water, including for power augmentation for periods of high ambient temperatures, the Agency would consider subcategorizing these units when burning non-natural gas fuels. For these units, dry combustion controls when firing non-natural gas fuels may be more appropriate. The EPA is soliciting comment on a range of 42 ppm to 58 ppm NO_X for medium combustion turbines operating at low capacity factors for the final rule.

ii. Intermediate and Base Load Medium Combustion Turbines

As noted previously, the EPA is proposing that combustion controls in combination with SCR is the BSER for medium combustion turbines operating at intermediate and base load capacity factors. Due to the limited number of medium combustion turbines operating at intermediate and base load capacity factors that have recently commenced construction, the EPA reviewed the emissions rates of medium simple cycle turbines with SCR. The EPA specifically reviewed hourly emissions rate information for highly efficient medium simple cycle turbines to account for the BSER in the final Carbon Pollution Standards, which is based on the use of highly efficient generation. Based on the analysis of the hourly data from these facilities, the EPA is proposing that a NO_X emissions rate of 3 ppm, based on the application of combustion controls in combination with SCR, has been demonstrated for medium combustion turbines operating at intermediate or base loads. The Bayonne Energy Center in New Jersey uses Siemens SGT–A65 combustion turbines with water injection plus SCR and has the lowest NO_X emissions rate for highly efficient medium combustion turbines. The facility has maintained the proposed emissions standard 100 percent of the time. The EPA evaluated a NO_X emissions rate of 2 ppm for periods of high load operation, but the historical 4-hour compliance rate drops to 91.82 percent. Based on current information, it does not appear that 2 ppm NO_X is consistently achievable for highly efficient medium combustion turbines.

c. Emissions Standards for Large Combustion Turbines

The NO_X emission standards for stationary combustion turbines in subpart KKKK with base load ratings of greater than 850 MMBtu/h of heat input are 15 ppm when combusting natural gas and operating at high loads, 42 ppm when combusting fuels other than natural gas and operating at high loads, and 96 ppm when operating at part loads. These existing NO_X standards are based on the application of dry and/or wet combustion controls alone or diffusion flame combustion at part load. Furthermore, these large combustion turbines are not subcategorized by annual capacity factors. In new subpart KKKKa, for large new, modified, or reconstructed stationary combustion turbines with base load ratings of greater than 850 MMBtu/h of heat input, the EPA is proposing to lower the NO_X emission standards to 3 ppm for natural gas-fired turbines and 5 ppm for large non-natural gas-fired turbines operating as intermediate or base load units (*i.e.,* at 12-calendar-month capacity factors of greater than 20 and 40 percent, respectively). These proposed NO_X standards are based on the application of a BSER of combustion controls in combination with SCR. The EPA also is proposing to maintain the same NO_X emission standards as in subpart KKKK for low load (*i.e.,* at 12-calendar-month capacity factors of less than or equal to 20 percent) large stationary combustion turbines—dry or wet combustion controls without SCR.

i. Low Load Large Combustion Turbines

The proposed BSER in new subpart KKKKa for low load (*i.e.,* at 12-calendar-month capacity factors of less than or equal to 20 percent) large stationary combustion turbines with base load ratings of greater than 850 MMBtu/h of heat input is combustion controls—the same as subpart KKKK. The EPA is proposing that there have not been significant changes in combustion controls for this subcategory and to maintain the emission standards in subpart KKKK—15 ppm NO_X for large natural gas-fired low load combustion turbines and 42 ppm NO_X for large non-natural gas-fired combustion turbines.

ii. Intermediate and Base Load Large Combustion Turbines

The EPA is proposing in new subpart KKKKa that combustion controls in combination with SCR is the BSER for intermediate and base load (*i.e.,* at 12-calendar-month capacity factors greater than 20 percent) combustion turbines with base load ratings of greater than 850 MMBtu/h of heat input. For this review of the NSPS, the EPA reviewed hourly emissions rate information for highly efficient large combined cycle combustion turbines to account for the BSER in the final Carbon Pollution Standards, which is based on the use of highly efficient generation. American Electric Power's (AEP) Dresden energy facility in Ohio was one of the combined cycle combustion turbines identified by the EPA in the Carbon Pollution Standards rulemaking with a

[47] The Martin Drake facility in Colorado uses General Electric LM2500XPRESS combustion turbines with dry combustion controls and has maintained the proposed emission standards 99.7 percent of the time. The Mustang facility in Oklahoma uses Siemens SGT–A65 combustion turbines with water injection and has maintained the proposed emission standards 99.97 percent of the time.

long-term low GHG emissions rate. The Dresden facility has SCR installed and has maintained a NO_X emissions rate of 4 ppm 99.99 percent of the time by highly efficient combined cycle turbines with SCR. However, this facility is relatively old (began operations in 2012), and the EPA also reviewed NO_X emissions data for more recently built highly efficient combined cycle facilities. For example, the Okeechobee Clean Energy Center in Florida, the Port Everglades combined cycle facility in Florida, and the Eagle Valley Generating Station in Indiana all use higher efficiency combustion turbine engines in combination with combustion controls and SCR and all have maintained the proposed emissions rate of 3 ppm NO_X 100 percent of the time. For large simple cycle combustion turbines, the units with the lowest NO_X emission rates are at Ocotillo Power Plant in Arizona. The facility uses General Electric LMS100 models with water injection plus SCR and has maintained the proposed emissions standard 99.84 percent of the time. The EPA believes that the emissions rate at the Ocotillo Power Plant could be improved through enhanced catalyst management and ammonia injection, which could reduce the emissions rate to the level achieved by the simple cycle turbines at the Bayonne Energy Center. Based on the analysis of the hourly data from these facilities, the EPA is proposing in new subpart KKKKa that a NO_X emissions rate of 3 ppm has been demonstrated for large highly efficient intermediate and base load combustion turbines. The EPA also evaluated a NO_X emissions rate of 2 ppm for periods of high load operation. While the combined cycle facilities have maintained a high load emissions rate of 2 ppm NO_X 99.73 percent of the time, the Ocotillo Power Plant has only maintained a high load emissions rate of 2 ppm 66.02 percent of the time. Based on current information, it does not appear that 2 ppm NO_X is consistently achievable for highly efficient large combustion turbines. The EPA is soliciting comment on the ability of large frame simple cycle turbines using SCR to achieve the proposed emissions rate.

d. Emission Standards for Combustion Turbines Operating at Part Loads, Located North of the Arctic Circle, or Operating at Ambient Temperatures of Less Than 0 °F

As discussed previously in section III.B.4.f, existing subpart KKKK subcategorizes stationary combustion turbines operating at part load (*i.e.,* less than 75 percent of the base load rating) and combustion turbines operating at low ambient temperatures.[48] The hourly NO_X emissions standard is less stringent during any hour when either of these conditions is met regardless of the type of fuel being burned. Subpart KKKK also has different hourly NO_X emissions standards depending on if the output of the combustion turbine is less than or equal to 30 MW (150 ppm NO_X) or greater than 30 MW (96 ppm NO_X) during part-load operation or when operating at low ambient temperatures. As described in section III.B.4.f, in new subpart KKKKa, the EPA is proposing to amend this size threshold for this subcategory such that the 150 ppm rate would be applicable to combustion turbines with base load ratings of less than or equal to 250 MMBtu/h of heat input and the 96 ppm rate would be applicable to combustion turbines with base load ratings greater than 250 MMBtu/h. In new subpart KKKKa, the EPA is proposing to maintain that the BSER for turbines operating at part load or at low ambient temperatures is diffusion flame combustion for all fuel types. Thus, the EPA also is proposing to maintain, based on the application of diffusion flame combustion, that the part-load and low ambient temperature NO_X emission standards are 150 ppm for turbines with base load ratings of less than or equal to 250 MMBtu/h of heat input and 96 ppm for combustion turbines with base load ratings greater than 250 MMBtu/h. In addition, the proposed part-load standard includes all periods of part-load operation, including startup and shutdown. However, in contrast to the part-load standards in existing subpart KKKK, in new subpart KKKKa, the EPA is proposing to lower the part-load threshold from less than 75 percent load to less than 70 percent of the combustion turbine's base load rating. See section III.B.4.f for additional discussion of this proposed reduction in the part-load threshold.

The determination to propose maintaining the BSER and NO_X emission standards in new subpart KKKKa for combustion turbines operating at part load or low ambient temperatures is based on a review of reported maximum hourly emissions rate data for recently constructed combustion turbines. The hourly data includes all periods of operation, including periods of startup and shutdown. For combustion turbines with base load ratings of greater than 250 MMBtu/h of heat input, 88 percent of simple cycle turbines and 98 percent of combined cycle turbines reported a maximum hourly NO_X emissions rate of less than 96 ppm. Based on this information, the EPA is proposing in new subpart KKKKa that a part-load standard of 96 ppm, which includes periods of startup and shutdown, is appropriate for combustion turbines with base load ratings of greater than 250 MMBtu/h of heat input. The EPA does not have CEMS data for combustion turbines with base load ratings of less than 250 MMBtu/h of heat input and is proposing to maintain the existing part-load standard in new subpart KKKKa of 150 ppm NO_X.

Finally, recognizing the wide discrepancy in the emissions standards for part-load operation as compared to full load (*i.e.,* above 70 percent on an hourly basis), the EPA in section III.B.4.f requests comment on a number of specific options for reducing that discrepancy.

13. Proposed Determination of BSER and NO_X Emissions Standards for Modified Stationary Combustion Turbines in 40 CFR Part 60, Subpart KKKKa

This section describes the proposed BSER and emission standards for modified stationary combustion turbines. For purposes of this subpart, the EPA would apply the definition of modification in the General Provisions, 40 CFR 60.14. The general rule under those provisions defines a ''modification'' as ''any physical change in, or change in the method of operation of, a stationary source'' that either ''increases the amount of any air pollutant emitted by such source or . . . results in the emission of any air pollutant not previously emitted.'' *Id.* 60.14(a).

In existing subpart KKKK, the BSER for modified combustion turbines is the use of combustion controls. While the BSER is generally the same as for new combustion turbines, the emissions standards are generally higher for a given subcategory to reflect that combustion controls can be more challenging to apply to modified combustion turbines compared to newly constructed combustion turbines. The NO_X emissions standards for modified combustion turbines in subpart KKKK range from 150 ppm to 15 ppm for turbines with base load ratings of less than or equal to 50 MMBtu/h of heat input and greater than 850 MMBtu/h, respectively.

Lean premix/DLN technology is specific to each combustion turbine model (*i.e.,* a combustor designed for a particular turbine model cannot simply

[48] While the EPA refers to this as the part-load standard, it includes an independent temperature component as well.

be installed on a different turbine model). If a combustion turbine were to be modified and more advanced DLN technology is not commercially available, the only option for the owner/operator to reduce the maximum hourly emissions rate would be to install SCR. However, one of the few ways the EPA is aware of that a combustion turbine can be modified such that the test in 60.14 modification criteria are triggered is if the owner/operator elects to upgrade the combustor technology to either increase the base load rating of the combustion turbine or to burn a fuel with a higher emissions rate. If an owner/operator replaces a combustor with another version with the same ratings as the previous combustor, such that the emission rate to the atmosphere of NO_X or SO_2 is not increased, the combustion turbine would not trigger the NSPS modification criteria. The EPA is soliciting comment on whether there are other actions that could increase the potential hourly emissions rate of a combustion turbine and thus may constitute ''modifications'' and whether any unique considerations exist for this subcategory.

For modified small and medium combustion turbines with base load ratings of less than or equal to 850 MMBtu/h of heat input, the EPA is proposing in new subpart KKKKa that the BSER is the use of combustion controls. A difference relative to the BSER for new and reconstructed combustion turbines compared to the BSER for certain modified combustion turbines, is that due to potentially high retrofit costs,[49] the EPA is proposing that SCR does not qualify as the BSER for modified medium base load combustion turbines. The emissions standard for all small and medium modified natural gas-fired combustion turbines is 25 ppm NO_X when operating at high loads. The proposed part load and non-natural gas standards for modified sources are the same as for new and reconstructed combustion turbines.

For modified combustion turbines with base load rating greater than 850 MMBtu/h, the EPA is proposing the same BSER and emissions standards as for new and reconstructed combustion turbines. The EPA is proposing that when retrofit costs are accounted for, the costs of SCR are reasonable and the same emissions standards are appropriate.

14. Combustion Turbines Firing Hydrogen

The EPA is proposing in subpart KKKKa to categorize new, modified, and reconstructed stationary combustion turbines that burn hydrogen as either natural gas-fired sources or non-natural gas-fired sources—depending upon the amount of hydrogen that is co-fired. Furthermore, the EPA is proposing that combustion turbines burning hydrogen should be subject to the same standards of performance for NO_X emissions as stationary combustion turbines firing natural gas or non-natural gas fuels. Specifically, the EPA is proposing that affected sources that burn less than or equal to 30 percent (by volume) hydrogen (blended with methane) should be categorized as natural gas-fired combustion turbines and subject to the same NO_X standards as combustion turbines burning natural gas, as defined in 60.4325a, according to the appropriate size-based subcategory listed in Table 1 to subpart KKKKa of part 60. Furthermore, for combustion turbines that burn greater than 30 percent (by volume) hydrogen (blended with methane), the EPA is proposing to categorize these sources as non-natural gas-fired combustion turbines and the applicable NO_X limit is proposed to be the same as the standard for non-natural gas-fired combustion turbines, again, depending on the classification of non-natural gas fuels in 60.4325a and the particular size-based subcategory listed in Table 1. *See* Table 1 to subpart KKKKa of part 60 for a complete listing of all subcategories of combustion turbines and their corresponding NO_X limits. The EPA solicits comment on the 30 percent (by volume) hydrogen threshold and its appropriateness for determining whether an affected source should be subject to the NO_X standard for natural gas or non-natural gas fuels. The EPA also solicits comment on alternative blend thresholds, from a low of 20 percent (by volume) blend to a high of 50 percent (by volume) blend, and whether an alternative volume would be a more appropriate basis for determining an applicable NO_X standard.

For this proposed action, the EPA evaluated the ability of new stationary combustion turbines to operate with certain percentages (by volume) of hydrogen blended into their fuel systems. This evaluation included the identification of specific properties of hydrogen that can impact NO_X emissions when the gas is combusted. The Agency also conducted an analysis of available control technologies and their ability to limit NO_X emissions when hydrogen is fired. The EPA also consulted with major combustion turbine manufacturers to collect information about improvements in available control technologies and assess the outlook for potential future turbine designs with hydrogen capabilities.

Although industrial combustion turbines have been burning byproduct fuels containing large percentages of hydrogen for decades, utility combustion turbines have only recently begun to co-fire smaller amounts of hydrogen as a fuel to generate electricity. Most turbine manufacturers are rapidly addressing technical challenges in new models of combustion turbines, such as the development of improved designs and components that can withstand higher temperatures or modified combustors that can reduce NO_X emissions.

a. Characteristics of Hydrogen Gas That Impact NO_X Emissions

Some of the technical challenges of firing hydrogen in a combustion turbine result from the physical characteristics of hydrogen gas. Perhaps the most significant challenge is that the flame speed of hydrogen gas is an order of magnitude higher than that of methane (*i.e.,* natural gas); at hydrogen blends of 70 percent or greater, the flame speed is essentially tripled compared to pure natural gas.[50] A higher flame speed can lead to localized higher temperatures, which can increase thermal stress on the turbine's components as well as increase thermal NO_X emissions.[51 52] It is necessary in combustion for the working fluid flow rate to move faster

[49] The EPA estimates that retrofitting a 90 MW combined cycle combustion turbine operating at a 65 percent capacity factor with SCR would cost approximately \$12,000/ton NO_X. For a 50 MW simple cycle combustion turbine operating at a 15 percent capacity factor, the estimated cost is approximately \$102,000/ton NO_X. See the *EGU NO_X Mitigation Strategies Final Rule Technical Support Document* in the regulatory docket (Docket ID EPA–HQ–OAR–2021–0668) for the final *Federal ''Good Neighbor Plan'' for the 2015 Ozone National Ambient Air Quality Standards.*

[50] National Energy Technology Laboratory (NETL). (August 12, 2022). *A Literature Review of Hydrogen and Natural Gas Turbines: Current State of the Art with Regard to Performance and NO_X Control.* A white paper by NETL and the U.S. Department of Energy (DOE). Accessed at *https://netl.doe.gov/sites/default/files/publication/A-Literature-Review-of-Hydrogen-and-Natural-Gas-Turbines-081222.pdf.*

[51] Guarco, J., Langstine, B., Turner, M. (2018). *Practical Consideration for Firing Hydrogen Versus Natural Gas.* Combustion Engineering Association. Accessed at *https://cea.org.uk/practical-considerations-for-firing-hydrogen-versus-natural-gas/.*

[52] Douglas, C., Shaw, S., Martz, T., Steele, R., Noble, D., Emerson, B., and Lieuwen, T. (2022). Pollutant Emissions Reporting and Performance Considerations for Hydrogen-Hydrocarbon Fuels in Gas Turbines. *Journal of Engineering for Gas Turbines and Power.* Volume 144, Issue 9: 091003. Accessed at *https://asmedigitalcollection.asme.org/gasturbinespower/article/144/9/091003/1143043/Pollutant-Emissions-Reporting-and-Performance.*

than the rate of combustion. When the combustion speed is faster than the working fluid, a phenomenon known as ''flashback'' occurs, which can damage injectors or other components and lead to upstream complications.[53] Other differences include a hotter hydrogen flame (4,089 °F) compared to a natural gas flame (3,565 °F)[54] and a wider flammability range for hydrogen than natural gas.[55] It is also important that hydrogen and natural gas are adequately mixed to avoid temperature ''hotspots,'' which can also lead to formation of greater volumes of NO_X.[56]

b. Hydrogen and Combustion Controls

The industrial and aeroderivative combustion turbines currently capable of co-firing at least 30 percent hydrogen (by volume) are generally simple cycle turbines that utilize wet low-emission (WLE) or diffusion flame combustion. For these turbines, water or steam injection is used to control emissions of NO_X, and the level of demineralized water injection can be varied for different levels of NO_X control. In addition, exhaust gas recirculation (EGR) in diffusion flame combustion turbines further reduces the oxygen concentration in the combustor and limits combustion temperatures and NO_X formation.

In terms of larger, heavy-duty frame combustion turbines that can co-fire 30 percent hydrogen (by volume), these models generally utilize WLE, dry low-emission (DLE), or DLN combustors. The more commonly used NO_X control for combined cycle turbines is DLN combustion. Even though the ability to fire hydrogen in combustion turbines using DLN combustors to reduce emissions of NO_X is currently more limited, all major manufacturers have developed DLN combustors for base load combined cycle combustion turbines that can fire hydrogen.[57] Moreover, the major manufacturers are designing combustion turbines that will be capable of combusting 100 percent hydrogen by 2030, with DLN designs that assure acceptable levels of NO_X emissions.[58 59]

c. Hydrogen and SCR

According to manufacturers, stationary combustion turbines firing less than 30 percent (by volume) hydrogen to date have not demonstrated measured increases in NO_X emissions. This analysis is based on the results of technology demonstrations and test burns on units with combustion controls and/or SCR. While DLN combustion controls can achieve low levels of NO_X, many new simple cycle and combined cycle combustion turbines with plans to fire hydrogen also use SCR for additional NO_X control. For example, a search in the NEEDS database[60] reveals that 16 existing stationary combustion turbines at six facilities list hydrogen as a fuel along with natural gas and/or distillate. In terms of control, 15 of these units have installed SCR and 10 have installed combustion controls. As discussed earlier in section III.B.7.b, the design level of control from SCR can be tied to the exhaust gas concentration. At higher levels of incoming NO_X from the combustion of hydrogen, either the reagent injection rate can be increased and/or the size of the catalyst bed can be increased.[61]

Other recent studies have also shown that stationary combustion turbines firing less than 30 percent (by volume) hydrogen to date have not demonstrated measured increases in NO_X emissions. In one such study, a NO_X ppm versus percent hydrogen correction curve was developed to illustrate that this NO_X ppm correction would be negligible for hydrogen/methane blends of less than 30 percent hydrogen, but begins to noticeably increase at hydrogen blends of greater than 30 percent.[62] However, it is the volumetric stack concentrations of pollutants, and not their actual mass production rates, which are measured using NO_X CEMS. As such, an additional fuel-based F-factor[63] is needed to properly convert NO_X concentrations in ppm to units of lb/MMBtu. F-factors for various fuels, such as natural gas and fuel oil, are listed in EPA Method 19 of 40 CFR part 60, appendix A. However, F-factors for hydrogen/methane blends (on a percent hydrogen basis) are not readily available in the EPA test methods. As such, a table of F-factors for hydrogen/methane blends is included in the docket for this proposed rule.

Several developers have announced installations with plans to initially co-fire lower percentages of hydrogen (by volume) before gradually increasing their co-firing percentages—to as high as 100 percent in some cases—depending on the availability of hydrogen fuel supplies. *See* 88 FR 33255, 33305; May 23, 2023. The goals of equipment manufacturers and the fact that existing combustion turbines have successfully demonstrated the ability to fire various percentages of hydrogen (by volume), combined with the potential for increased NO_X emissions, align with the EPA's decision to address the issue of hydrogen firing in combustion turbines as proposed in new subpart KKKKa.

d. Future Combustion Turbine Capabilities

As mentioned earlier, most turbine manufacturers are working to increase the levels of hydrogen combustion in new and existing turbine models while limiting emissions of NO_X. This is true of the three largest turbine manufacturers in the world: General Electric (GE) and Siemens both have goals to develop 100 percent DLE or DLN hydrogen combustion capability in their turbines by 2030.[64 65 66] Mitsubishi

[53] Inoue, K., Miyamoto, K., Domen, S., Tamura, I., Kawakami, T., & Tanimura, S. (2018). *Development of Hydrogen and Natural Gas Co-firing Gas Turbine.* Mitsubishi Heavy Industries Technical Review. Volume 55, No. 2. June 2018. Accessed at *https://power.mhi.com/randd/technical-review/pdf/index_66e.pdf.*

[54] Andersson, M., Larfeldt, J., Larsson, A. (2013). *Co-firing with hydrogen in industrial gas turbines.* Accessed at *http://sgc.camero.se/ckfinder/userfiles/files/SGC256(1).pdf.*

[55] Andersson, M., Larfeldt, J., Larsson, A. (2013). *Co-firing with hydrogen in industrial gas turbines.* Accessed at *http://sgc.camero.se/ckfinder/userfiles/files/SGC256(1).pdf.*

[56] Guarco, J., Langstine, B., Turner, M. (2018). *Practical Consideration for Firing Hydrogen Versus Natural Gas.* Combustion Engineering Association. Accessed at *https://cea.org.uk/practical-considerations-for-firing-hydrogen-versus-natural-gas/.*

[57] Siemens Energy (2021). *Overcoming technical challenges of hydrogen power plants for the energy transition.* NS Energy. Accessed at *https://www.nsenergybusiness.com/news/overcoming-technical-challenges-of-hydrogen-power-plants-for-energy-transition/.*

[58] Simon, F. (2021). *GE eyes 100% hydrogen-fueled power plants by 2030.* Accessed at *https://www.euractiv.com/section/energy/news/ge-eyes-100-hydrogen-fuelled-power-plants-by-2030/.*

[59] Patel, S. (2020). *Siemens' Roadmap to 100% Hydrogen Gas Turbines.* Accessed at *https://www.powermag.com/siemens-roadmap-to-100-hydrogen-gas-turbines/.*

[60] See the U.S. Environmental Protection Agency's (EPA) National Electric Energy Data System database. NEEDS rev 06–06–2024. Accessed at *https://www.epa.gov/power-sector-modeling/national-electric-energy-data-system-needs.*

[61] Siemens Energy (2021). *Overcoming technical challenges of hydrogen power plants for the energy transition.* NS Energy. Accessed at *https://www.nsenergybusiness.com/news/overcoming-technical-challenges-of-hydrogen-power-plants-for-energy-transition/.*

[62] At 30 percent hydrogen, the NO_X ppm correction factor would be approximately 1.034 at 29.53 in. Hg and an adiabatic flame temperature of 3,140 °F. Georgia Institute of Technology and Electric Power Research Institute. *NO_X Emissions from Hydrogen-Methane Fuel Blends.* See Docket ID No. EPA–HQ–OAR–2024–0419.

[63] An F-Factor is the ratio of the gas volume of the products of combustion to the heat content of the fuel.

[64] Simon, F. (2021). *GE eyes 100% hydrogen-fueled power plants by 2030.* Accessed at *https://www.euractiv.com/section/energy/news/ge-eyes-100-hydrogen-fuelled-power-plants-by-2030/.*

[65] Patel, S. (2020). *Siemens' Roadmap to 100% Hydrogen Gas Turbines.* Accessed at *https://www.powermag.com/siemens-roadmap-to-100-hydrogen-gas-turbines/.*

[66] de Vos, Rolf (2022). *Ten fundamentals to hydrogen readiness.* Accessed at *https://*

Continued

is targeting development of 100 percent DLN hydrogen combustion capable turbines by 2025.[67]

Turbine models such as the GE 7HA.02 can co-fire 50 percent hydrogen (by volume) with the DLN 2.6e combustor, GE's most recent combustor design.[68] GE offers other DLE and DLN combustion turbines that can co-fire up to 33 percent hydrogen (by volume) and a diffusion flame model that can co-fire 85 percent hydrogen (by volume).[69] [70]

Siemens offers an upgrade package called ''H2DeCarb'' to enable its E- and F-Class turbines to combust larger quantities of hydrogen (typically 50 to 60 percent).[71] Furthermore, Siemens currently offers heavy-duty combustion turbines with hydrogen blending capabilities of 30 to 50 percent (by volume), depending on the turbine model and type of combustion system.[72] Other Siemens models include aeroderivative engines and medium industrial combustion turbines that range from 10 to 75 percent hydrogen (by volume) capability.[73]

Mitsubishi has also been developing advanced combustors to fire high levels of hydrogen with limited NO_X emissions in addition to supporting hydrogen production and storage infrastructure.[74] For example, the manufacturer has developed several frame models that range between 30 and 1,280 MW in size that can co-fire 30 percent hydrogen (by volume) with currently available DLN technologies, and each of the available combustion turbine models is being developed to fire 100 percent hydrogen with DLN combustors.[75] [76]

With several models of larger combustion turbines able to co-fire lower percentages of hydrogen (by volume) with current technologies, some new and existing facilities have announced plans to initially co-fire up to 30 percent hydrogen (by volume) and up to 100 percent when the additional fuel becomes available. As noted earlier, certain turbine models will require combustor upgrades or retrofits before being ready to eventually fire 100 percent hydrogen. These pre-planned retrofits align to turbine compatibility with blending high volumes and operating exclusively on hydrogen.

Some of the turbine projects that have recently been built or that are currently under construction are being developed with the understanding that advanced combustors will be retrofittable to the types of turbines installed at these facilities. It is worth noting that in many cases, existing turbines can co-fire larger volumes of hydrogen without significant re-engineering. These older turbines have a simpler design that accommodates switching from natural gas to hydrogen. However, almost all new turbines are designed with more sophisticated burners that closely control the mixture of air and fuel to maximize efficiency while limiting NO_X generation, specifically for burning natural gas, not hydrogen. Because hydrogen has very different characteristics from natural gas, such as higher flame temperature, these burners need to be re-engineered to accommodate large volumes of hydrogen while also still adequately limiting NO_X generation. Depending on the changes necessary for a combustion turbine to accommodate the firing of hydrogen, a permitting authority may require that a source undertaking such a retrofit be subject to an NSR permitting process, independent of whether the source triggers the NSPS modification or reconstruction criteria.

The EPA solicits comment on issues concerning stationary combustion turbines that are planning to co-fire or are designed to co-fire greater than 30 percent (by volume) hydrogen in the future. Topics of interest include costs, control technology considerations and challenges, and NO_X emissions. Specifically, the EPA seeks comment on the costs associated with co-firing high percentages (by volume) of hydrogen. This includes information on turbine designs and necessary components, upgrades, and retrofits. The EPA also solicits comment on whether SCR is an effective NO_X emission control technology for combustion turbines co-firing high percentages (by volume) of hydrogen and whether there are advancements being made in SCR technology to better control NO_X emissions when hydrogen is co-fired. Furthermore, the EPA solicits comment on specific combustion turbine demonstrations or emissions test data in which high percentages (by volume) of hydrogen have been co-fired in a combustion turbine, under what operating conditions or load, the duration, the NO_X emission control technology used, and the recorded NO_X emissions correlated to various percentages (by volume) of hydrogen during the demonstration or test burn.

15. Collocated Battery Storage and Potential NO_X Emissions

At a few locations in the U.S., both simple cycle and combined cycle combustion turbine EGUs have been located at the same site as battery storage technology. Battery storage works by converting electrical energy to chemical energy and back again as needed—during those conversions some of the energy is lost as heat and other inefficiencies so that the roundtrip efficiency is typically around 85 percent.[77] Consequently, the net generation from the battery is negative (the electrical energy output is less than the electrical energy input). However, by being able to be charged when electricity demand is low and discharged when it is high, battery storage can provide a useful role to the grid.

In some cases, collocated battery storage and combustion turbine EGUs operate independently—the batteries are charged by grid electricity and provide arbitrage and/or ancillary services while the combustion turbines are dispatched as normal (see for example, the Moss Landing Power Plant, Moss Landing, California [78]). Often, the batteries in this case are lithium-ion based with a 4-hour

www.siemens-energy.com/global/en/news/magazine/2022/hydrogen-ready.html.

[67] Power Magazine (2019). *High Volume Hydrogen Gas Turbines Take Shape.* Accessed at *https://www.powermag.com/high-volume-hydrogen-gas-turbines-take-shape/.*

[68] General Electric (GE). (February 2022). Hydrogen Overview (online brochure). Accessed at *https://www.ge.com/content/dam/gepower-new/global/en_US/downloads/gas-new-site/future-of-energy/hydrogen-overview.pdf.*

[69] General Electric (GE). (2022). Hydrogen Overview for Aeroderivative Gas Turbines. Accessed at *https://www.ge.com/content/dam/gepower-new/global/en_US/images/gas-new-site/microsites/en/sa/saudi-industrial/h2-aero-overview-march24-2022-ga-r2.pdf.*

[70] General Electric (GE) (2019, February). *Power to Gas: Hydrogen for Power Generation.* Accessed at *https://www.ge.com/content/dam/gepower/global/en_US/documents/fuel-flexibility/GEA33861%20Power%20to%20Gas%20-%20Hydrogen%20for%20Power%20Generation.pdf.*

[71] Siemens Energy Zero Emission Hydrogen Turbine Center. Accessed at *https://www.siemens-energy.com/global/en/priorities/future-technologies/hydrogen/zehtc.html.*

[72] Siemens (2022). Hydrogen power and heat with Siemens Energy gas turbines. Accessed at *https://www.siemens-energy.com/global/en/offerings/technical-papers/download-hydrogen-gas-turbine-readiness-white-paper.html.*

[73] Siemens (2020). Hydrogen power with Siemens gas turbines. *https://www.infrastructureasia.org/-/media/Articles-for-ASIA-Panel/Siemens-Energy---Hydrogen-Power-with-Siemens-Gas-Turbines.ashx.*

[74] Mitsubishi Heavy Industries. Accessed at *https://solutions.mhi.com/power/decarbonization-technology/hydrogen-gas-turbine/.*

[75] Mitsubishi Heavy Industries (2021). Hydrogen Power Generation Handbook. Accessed at *https://solutions.mhi.com/sites/default/files/assets/pdf/et-en/hydrogen_power-handbook.pdf.*

[76] See *https://power.mhi.com/special/hydrogen.*

[77] National Renewable Energy Laboratory (NREL). 2024 Annual Technology Baseline. Utility-Scale Battery Storage. U.S. Department of Energy (DOE). Available at *https://atb.nrel.gov/electricity/2024/utility-scale_battery_storage.*

[78] U.S. Energy Information Administration (EIA). Form 860. Schedule 3, Energy Storage Data. 2022. Available at *https://www.eia.gov/electricity/data/eia860/.*

storage duration and various capacities. The electricity charging the battery may come from a mix of non-fossil and fossil generating sources, the latter of which would have associated NO_X and other emissions. Regardless of the source of grid energy charging the battery, because the efficiency of the battery is less than 100 percent and the net generation of the battery is negative, the cumulative emission rate of the power plant on a lb/MWh-net basis would necessarily be higher. Regarding the operation of the combustion turbine, because it is likely independent of the battery, it is unclear whether the NO_X emissions would be directly impacted.

In a different configuration, the battery is integrated with the combustion turbine, so that the combustion turbine may charge the battery directly (although it is possible it could also be charged from the grid). This integrated case is sometimes referred to as a hybrid combustion turbine.[79] The latter has been applied at a few simple cycle combustion turbines (see for example, Center Hybrid, Norwalk, California [80]). By integrating battery storage with the combustion turbine, the hybrid simple cycle combustion turbine has the capability of providing contingency (''spinning'') reserves (*i.e.,* the ability to start up almost instantly), ancillary services, and/or provide black-start capability.[81] [82] The battery for the hybrid combustion turbine is typically sized to provide about 30 minutes to 1 hour of generation, and sized around 20 percent of the capacity of the associated combustion turbine EGU. In a wholesale market where the unit provides contingency reserves only, the hybrid unit can receive payment for the ability to provide those services, potentially with limited operation of the combustion turbine part of the unit. Systemwide, it is possible this could displace base load fossil generation that would otherwise be operating at lower loads (and with potentially higher hourly NO_X emission rates) to provide reserve margins. However, how the hybrid unit operates depends on the market valuation of contingency reserves and how the owner of the unit chooses to bid the unit. While there is a potential systemwide benefit to hybrid combustion turbines, the direct impact on the emission rates of the combustion turbine at the unit level is unclear. Modifications may be made to enable generation of the combustion turbine at low loads (*i.e.,* to pick up from the capacity of the battery), subsequently, the unit could operate more at low loads where it may be less efficient and the NO_X produced from combustion is higher. Aside from potentially affecting the loads the unit operates at, it is unclear whether there is a direct technical impact on the NO_X emission rate of the unit. As a further complication, when installing collocated battery storage, it may be that changes to NO_X controls could have been made at the same time (*e.g.,* installation or updates to SCR) that directly impacted historical NO_X emissions data.

The EPA is soliciting comment on the potential impact of collocated battery storage on unit level NO_X emissions of combustion turbines, particularly in the case of the hybrid combustion turbine, including any data that would support any asserted impact on an hourly or instantaneous basis and the technical root cause of such an impact.

16. Additional Proposed Amendments to the NO_X Standards

a. NO_X Part-Load Standards During Startup and Shutdown

Since startups and shutdowns are part of the regular operating practices of stationary combustion turbines, the EPA is proposing to include in new subpart KKKKa a part-load NO_X emissions standard that would apply during periods of startup and shutdown. Since periods of startup and shutdown are by definition periods of low load, and since the ''part-load standard'' is based on the emissions rate achieved by a diffusion flame combustor instead of DLN combustion controls, the Agency is proposing to conclude that this standard would be appropriate. Through analysis of continuous emission monitoring system (CEMS) data, the EPA has determined that including periods of startup and shutdown in the standard would not result in non-compliance with the standard. The EPA analyzed NO_X CEMS data from existing multiple combustion turbines and the theoretical compliance rate with a 4-hour rolling average, including all periods of operation, was demonstrated to be achievable. The Agency is unable to determine whether any of the potential hours of theoretical non-compliant emissions were the result of either a malfunction of the NO_X CEMS or combustion control equipment. Since the data reported to the EPA is hourly average capacity factors, the Agency was also unable to identify all periods when the part-load standard would apply and the actual level of theoretical compliance would be higher.[83]

b. Recognizing the Benefit of Avoided Line Losses for CHP Facilities

We are proposing to recognize in new subpart KKKKa the environmental benefit of electricity generated by CHP facilities to account for the benefit of on-site generation avoiding losses from the transmissions and distribution of the electricity. Actual line losses vary from location to location, but we are proposing a benefit of 5 percent avoided transmission and distribution losses when determining the electric output for CHP facilities. To avoid CHP facilities only providing a trivial amount of thermal energy from qualifying for the transmission and distribution benefit, we are proposing to restrict the 5 percent benefit to CHP facilities where at least 20 percent of the annual output is useful thermal output.

C. SO_2 Emission Standards

The gaseous compound SO_2 is composed of sulfur and oxygen (O_2) and is a criteria air pollutant that often forms when a fuel containing sulfur is burned. SO_2 is also a precursor to fine particulates or $PM_{2.5}$, another criteria air pollutant. Air quality standards for SO_2 are designed to protect against exposure to the entire group of sulfur oxides (SO_X); control measures that reduce SO_2 can generally be expected to reduce exposure to all gaseous SO_X. For new, modified, or reconstructed stationary combustion turbines, the BSER for limiting emissions of SO_2 has been demonstrated to be the combustion of low-sulfur fuels. Since the promulgation of the original NSPS in 1979, in subpart GG of 40 CFR part 60, the sulfur content of the primary fuels fired in stationary combustion turbines has continued to decline, and the increased stringency of this best system is reflected in the existing NSPS, subpart KKKK of 40 CFR

[79] GE Vernova. LM6000 Hybrid EGT. Available at *https://www.gevernova.com/gas-power/services/gas-turbines/upgrades/hybrid-egt.*

[80] U.S. Energy Information Administration (EIA). Form 860. Schedule 3, Energy Storage Data. 2022. U.S. Department of Energy (DOE). Available at *https://www.eia.gov/electricity/data/eia860/.*

[81] Gridwell. Report on Hybrid Storage Technology. July 2018. Available at *https://www.gridwell.com/_files/ugd/fe68bf_ff74a8c24c6d4907b8bea661be9f99df.pdf.*

[82] Electric Power Research Institute (EPRI). Hybridized Gas Turbine Plus Battery Energy Storage Systems. September 2021. Available at *https://www.epri.com/research/products/00000000300 2022317.*

[83] The part-load standard is applicable to the entire hour if the combustion turbine operates at part-load at any point during the hour. When determining the applicable standard for the hour the EPA assumed the combustion turbine was operated at the hourly average capacity factor for the entire 60 minute period. Hours with less than 60 minutes of operation were assigned the part load standard regardless of the reported hourly average capacity factor.

part 60, which was amended in 2006 to lower the SO_2 standards.

Again, natural gas is the primary fuel fired in most stationary combustion turbines. Today, the sulfur content of ''pipeline quality'' natural gas in the U.S. is limited to 20 grains or less total sulfur per 100 standard cubic feet (gr/100 scf). In noncontinental areas where fuel availability can be limited, the sulfur content of natural gas is permitted to be as high as 140 gr/100 scf. Distillate fuel oil (*i.e.,* diesel fuel) is a secondary or backup fuel for most combustion turbines, and due to the EPA's regulations in the transportation sector dating back to 1993, its sulfur content must be limited by fuel producers. In subpart KKKK, the sulfur content of distillate fuel oil in continental areas must not contain more than 500 ppmw sulfur. This is considered low-sulfur diesel and is widely available as a fuel for stationary combustion turbines. However, in noncontinental areas, the availability of this low-sulfur diesel is limited, and distillate or fuel oil can contain as much as 4,000 ppmw sulfur. These sulfur contents are approximately equivalent to 0.05 percent by weight sulfur in continental areas and 0.4 percent by weight in noncontinental areas.

The application of this BSER of low-sulfur fuels is reflected in the existing standards of performance in subpart KKKK as discussed in section II.C and is applicable to all new, modified, or reconstructed combustion stationary turbines constructed after February 18, 2005, regardless of size. However, there is a subcategory for turbines located in noncontinental areas that may not have access to the same low-sulfur natural gas or distillate fuels as affected sources in continental areas.

In terms of compliance with subpart KKKK, the use of low-sulfur fuels is demonstrated by using the fuel quality characteristics in a current, valid purchase contract, tariff sheet, or transportation contract, or through representative fuel sampling data that show that the potential sulfur emissions of the fuel do not exceed the standard. It is also expected that stationary combustion turbines using low-sulfur fuels would have lower O&M expenses associated with reduced formation of acid compounds inside the turbine. These lower O&M expenses are expected to reduce or even eliminate any overall costs associated with the use of low-sulfur fuels on new, modified, or reconstructed stationary combustion turbines.

For this rulemaking, proposed as subpart KKKKa in 40 CFR part 60, the EPA conducted a CAA-required review of existing control technologies for limiting SO_2 emissions from new, modified, or reconstructed stationary combustion turbines. This review focused on the determination in subpart KKKK that the best system for limiting emissions of SO_2 from all stationary combustion turbines is the continued use of pipeline natural gas and low-sulfur distillate fuel oil (*i.e.,* diesel). The sulfur content of delivered natural gas continues to meet the fuel industry standard of 20 gr/100 scf. For distillate fuel oil, the SO_2 emissions standard in subpart KKKK is based on distillate fuels with a sulfur content of no more than 500 ppmw in continental areas. The production of low-sulfur diesel with a sulfur content of 500 ppmw has changed since the promulgation of subpart KKKK as the EPA has continued to phase in more stringent diesel production standards for on-road and nonroad vehicles, locomotives, and certain types of marine vessels. *See* 69 FR 38958; June 29, 2004. As a consequence, ultra-low sulfur diesel (ULSD) that is limited to 15 ppmw is an available fuel that can be fired in stationary combustion turbines in continental areas. However, pipeline natural gas remains the primary fuel fired in most stationary combustion turbines, and the burning of distillate fuel oil is a secondary or backup/emergency fuel in many cases. Also, reliable access to ULSD in certain areas remains questionable, as does documented information about its consistent use in non-utility sectors that operate stationary combustion turbines. This is especially true of stationary combustion turbines located in noncontinental areas as defined in 60.4420 and proposed in 60.4420a. Therefore, in subpart KKKKa, the EPA solicits comment on the extent of the current use of ULSD at affected facilities, including information on the availability of ULSD in both continental and noncontinental areas.

The EPA's review of the NSPS did not reveal the use of any additional control technologies that have been applied to stationary combustion turbines to further limit SO_2 emissions. This includes flue gas desulfurization (FGD) post-combustion control technology—the most common type of SO_2 control nationwide aside from the use of low-sulfur fuels. Generally, this control technology is not used to limit emissions of SO_2 from natural gas-fired stationary combustion sources. Instead, FGD is used to remove SO_2 from the exhaust streams of coal- and oil-fired utility and industrial boilers, incinerators, cement kilns, metal smelters, and petroleum refineries. This technology was discussed in the original NSPS, subpart GG, for stationary gas turbines, and is not an applicable alternative for the control of SO_2 emissions from natural gas-fired stationary combustion turbines, which are designed to fire low-sulfur fuels. The use of FGD also has environmental impacts due to increased water usage as well as the disposal of waste products.

Based on this review, which demonstrates that the burning of low-sulfur fuels continues to be an effective control for SO_2 emissions, the EPA is proposing to maintain in new subpart KKKKa that the use of low-sulfur fuels is the BSER for limiting SO_2 emissions from new, modified, and reconstructed stationary combustion turbines, regardless of the rated heat input and utilization of the turbine. Accordingly, the application of this BSER is reflected in the SO_2 standards proposed in subpart KKKKa. When the EPA's analyses show that the BSER for affected facilities remains the same, and available information from the implementation and enforcement of current requirements indicate that emission limitations and percent reductions beyond those required by the current standards are not achieved in practice, the EPA proposes to retain the current standards. The standards of performance proposed in subpart KKKKa are identical to those promulgated in subpart KKKK and are the same for all turbines regardless of size. Nonetheless, we request comment on whether ULSD has become so widely available that it would be appropriate to update the SO_2 standards for distillate fuels at combustion turbines based on its use, at least in continental areas, whether there are practical barriers to its use, and/or whether a subcategory-specific SO_2 standard for firing ULSD would be appropriate.

Specifically, as proposed in section 60.4330a of subpart KKKKa, an affected source may not cause to be discharged into the atmosphere from a new, modified, or reconstructed stationary combustion turbine any gases that contain SO_2 in excess of 110 ng/J (0.90 lb/MWh) gross energy output or 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input. For turbines located in noncontinental areas, an affected source may not cause to be discharged into the atmosphere any gases that contain SO_2 in excess of 780 ng/J (6.2 lb/MWh) gross energy output or 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input.

The EPA expects no additional SO_2 reductions based on the standards proposed in subpart KKKKa. Although the EPA anticipates that the demand for electric output from stationary combustion turbines in the power and industrial sectors will increase during the next 8 years, the Agency does not expect significant increases in SO_2 emissions from the sector prior to the next CAA-required review of the NSPS. The EPA also does not expect any adverse energy impacts from the proposed SO_2 standards in subpart KKKKa. All affected sources will be able to comply with the proposed rule without any additional controls, and the standards and the best system have not changed from subpart KKKK in 2006.

As such, these affected sources would be required to continue monitoring and demonstrating compliance with the fuel sulfur content limits as specified in 60.4365 and 60.4365a.

D. Consideration of Other Criteria Pollutants

When proposing the current subpart KKKK requirements (70 FR 8314, February 18, 2005) (2005 NSPS Proposal), the EPA considered the need to establish standards of performance for criteria pollutants beyond NO_X and SO_2. These included carbon monoxide (CO) and particulate matter (PM).

1. Carbon Monoxide

Carbon monoxide is a product of incomplete combustion when there is insufficient residence time at high temperature, or incomplete mixing to complete the final step in fuel carbon oxidation. The oxidation of CO to CO_2 at combustion turbine temperatures is a slow reaction compared to most hydrocarbon oxidation reactions. In combustion turbines, failure to achieve CO burnout may result from quenching by dilution air. With liquid fuels, this can be aggravated by carryover of larger droplets from the atomizer at the fuel injector. Carbon monoxide emissions are also dependent on the loading of the combustion turbine. For example, a combustion turbine operating under full load would experience greater fuel efficiencies, which will reduce the formation of CO.

Turbine manufacturers have significantly reduced CO emissions from combustion turbines by developing lean premix technology. Most of the newer designs for turbines incorporate lean premix technology. Lean premix combustion design not only produces lower NO_X than diffusion flame technology, but also lowers CO and volatile organic compounds (VOC). In the 2005 NSPS Proposal, the EPA determined that ''with the advancement of turbine technology and more complete combustion through increased efficiencies, and the prevalence of lean premix combustion technology in new turbines, it is not necessary to further reduce CO in the proposed rule'' and the EPA proposed that no CO emission limitation be developed for the combustion turbine NSPS.

2. Particulate Matter

In the 2005 NSPS Proposal, the EPA noted that PM emissions from turbines result primarily from carryover of noncombustible trace constituents in the fuel. Particulate matter emissions are negligible with natural gas firing due to the low sulfur content of natural gas. Emissions of PM are only marginally significant with distillate oil firing because of the low ash content and are expected to decline further as the sulfur content of distillate oil decreases due to other regulatory requirements. As such, the EPA proposed that an emission limitation for PM emissions from stationary combustion turbines is not necessary.

3. Technology Review and Revision of the Combustion Turbine National Emission Standards for Hazardous Air Pollutants (NESHAP)

The EPA is conducting a separate rulemaking to address deficiencies in the current NESHAP standards (*i.e.,* establish emission standards for hazardous air pollutants (HAP) where no standards currently exist from new and existing stationary combustion turbines) and conducting a technology review (under CAA section 112(d)(6)) to evaluate whether more stringent standards are warranted. To support that rulemaking, the EPA collected emissions data, under authority of CAA section 114, from a variety of combustion turbines—of differing subcategories, sizes, ages, fuels, *etc.* The EPA collected emissions of HAP metals (*e.g.,* nickel, chromium, *etc.*), acid gas HAP (hydrochloric acid and hydrofluoric acid), and formaldehyde to assist in establishing those emission standards. The EPA also collected emissions data for filterable PM and CO (filterable PM is often used as a surrogate for the non-mercury HAP metals and CO has been used as a surrogate for organic HAP). The emissions data are available on the EPA's combustion turbine NESHAP website [84] and in the docket for this rulemaking.

As part of the combustion turbine NESHAP rulemaking, the EPA expects to establish emission standards for stationary combustion turbines that are located at major sources of HAP emissions.[85] These emission standards may include limits for the HAP metals, formaldehyde, and the acid gas HAP. In addition, the EPA may also consider the establishment of an alternative emission limit for filterable PM as a surrogate for the HAP metals. Some combustion turbines are currently subject to an emission limit for formaldehyde. As such, some combustion turbines have installed an oxidation catalyst to control formaldehyde emissions. Oxidation catalysts may also be used to minimize emissions of CO.

At this time, the EPA believes it is prudent to defer consideration of the need for CO and PM standards of performance until the Agency has completed the NESHAP rulemaking, which will cover both new and existing sources. The EPA solicits comment on this approach and on the need to establish standards of performance for PM and CO under CAA section 111(b).

E. Additional Subpart KKKKa Proposals

1. Definition of Noncontinental Area

The EPA's review of low-sulfur fuels for this NSPS indicates that since subpart KKKK was promulgated, the availability of low-sulfur diesel and potentially ULSD has increased in States and territories previously defined as noncontinental areas for purposes of compliance with the SO_2 emission standards in subpart KKKK. As a result, in subpart KKKKa, the EPA is proposing to remove Hawaii, the Commonwealth of Puerto Rico, and the U.S. Virgin Islands from the definition of noncontinental area. This proposed change would require new, modified, and reconstructed stationary combustion turbines in Hawaii, Puerto Rico, and the Virgin Islands to demonstrate compliance with the same SO_2 standards proposed in subpart KKKKa for continental areas. As discussed in the previous section, those standards are based on fuel oil with sulfur content limited to approximately 0.05 percent sulfur by weight (500 ppmw).

Based on available information reviewed for this rulemaking, the EPA proposes to maintain in subpart KKKKa that Guam, American Samoa, the Northern Mariana Islands, and offshore platforms be included in the definition

[84] Stationary Combustion Turbines: National Emission Standards for Hazardous Air Pollutants (NESHAP) accessible at: *www.epa.gov/stationary-sources-air-pollution/stationary-combustion-turbines-national-emission-standards.*

[85] The term ''major source'' means any stationary source or group of stationary sources located within a contiguous area and under common control that emits or has the potential to emit considering controls, in the aggregate, 10 tons per year or more of any hazardous air pollutant or 25 tons per year or more of any combination of hazardous air pollutants. *See* CAA 112(a)(1).

of noncontinental area and those locations would continue to be allowed to meet the existing standards for higher sulfur fuels. This is due to the fact these locations continue to have limited access to the same low-sulfur fuels as facilities in continental areas. The EPA solicits comment on the extent to which Guam, American Samoa, the Northern Mariana Islands, and offshore platforms have access to low-sulfur and/or ULSD distillate fuels and whether any of those territories or locations should no longer be included in the definition of noncontinental area.

2. Clarification of Fuel Analysis Requirements for Determination of SO_2 Compliance

The EPA is proposing in subpart KKKKa rule language to clarify the intent of the rule in that if a source elects to perform fuel sampling to demonstrate compliance with the SO_2 standard, the initial test must be conducted using a method that measures multiple sulfur compounds (*e.g.,* hydrogen sulfide, dimethyl sulfide, carbonyl sulfide, and thiol compounds). Alternate test procedures can be used only if the measured sulfur content is less than half of the applicable standard. In addition, the EPA is proposing to allow fuel blending to achieve the applicable SO_2 standard. Under the proposed language, an owner/operator of an affected facility would be able to burn higher sulfur fuels as long as the average fuel fired meets the applicable SO_2 standard at all times. Finally, the primary method of controlling emissions is through selecting fuels containing low amounts of sulfur or through fuel pretreatment operations that can operate at all times, including periods of startup and shutdown as discussed below in section III.G.

3. Expanding the Application of Low-Btu Gases

For stationary combustion turbines combusting 50 percent or more biogas (based on total heat input) per calendar month, subpart KKKK in 40 CFR part 60 established a maximum allowable SO_2 emissions standard of 65 ng SO_2/J (0.15 lb SO_2/MMBtu) heat input. This standard was set to avoid discouraging the development of energy recovery projects that burn landfill gases to generate electricity in stationary combustion turbines. *See* 74 FR 11858; March 20, 2009. Stationary combustion turbine technologies using other low-Btu gases are also commercially available. These technologies can burn low-Btu content gases recovered from steelmaking (*e.g.,* blast furnace gas and coke oven gas), coal bed methane, *etc.* Like biogas, substantial environmental benefits can be achieved by using these low-Btu gases to fuel combustion turbines instead of flaring or direct venting to the atmosphere. Therefore, in subparts KKKK and KKKKa, the EPA is proposing to amend and expand the application of the existing 65 ng SO_2/J (0.15 lb SO_2/MMBtu) heat input emissions standard to include stationary combustion turbines combusting 50 percent or more (on a heat input basis) any gaseous fuels that have heating values less than 26 megajoules per standard cubic meter (MJ/scm) (700 Btu/scf) per calendar month.

To account for the environmental benefit of productive use and simplify compliance for low-Btu gases, the Agency considers it appropriate to base the proposed SO_2 standard on a fuel concentration basis as an alternative to a lb/MMBtu basis. The original subpart KKKK standard for SO_2 that was proposed in 2005 (70 FR 8314; February 18, 2005) was based on the sulfur content in distillate oil and included a standard of 0.05 percent sulfur by weight (500 ppmw). In general, emission standards are applied to a gaseous mixture by volume (ppmv), not by weight (ppmw). Basing the standard on a volume basis would simplify compliance and minimalize burden to the regulated community. Therefore, the EPA is proposing in subparts KKKK and KKKKa a fuel specification standard of 650 mg sulfur/scm (or 28 gr sulfur/100 scf) for low-Btu gases. This is approximately equivalent to a standard of 500 ppmv sulfur and is in the units directly reported by most test methods.

4. Proposed Amendments To Simplify NSPS

This rulemaking includes some additional proposals for subpart KKKKa and proposed amendments to subart KKKK intended to simplify the regulatory burden.

a. Compliance Demonstration Exemption for Units Out of Operation

The EPA is proposing in new subpart KKKKa, and proposing to amend in subpart KKKK, that units that are out of operation at the time of a required performance test are not required to conduct the performance test until 45 days after the facility is brought back into operation. The EPA concludes that it is not appropriate to require an affected facility that is not currently in operation to start up in order to conduct a performance test for the sole purpose of demonstrating compliance with the NSPS.

Similarly, owners/operators of a combustion turbine that has operated 50 hours or less since the previous performance test was required to be conducted can request an extension of the otherwise required performance test from the appropriate EPA Regional Office until the turbine has operated more than 50 hours. This provision is specific to a particular fuel, and an owner/operator permitted to burn a backup fuel, but that rarely does so, can request an extension on testing on that particular fuel until it has been burned for more than 50 hours.

b. Authorization of a Single Emissions Test

For similar, separate affected facilities under common ownership, not equipped with SCR, and using dry combustion control equipment, the EPA is proposing to include in new subpart KKKKa, and is proposing to amend in subpart KKKK, that the Administrator or delegated authority may authorize a single emissions test as adequate demonstration for up to four additional separate affected facilities of the same combustion turbine model and using the same dry combustion control technology as long as: (1) The most recent performance test for each affected facility shows that performance of each affected facility is 75 percent or less of the applicable emissions standard; (2) the manufacturer's recommended maintenance procedures for each control device are followed; and (3) each affected facility conducts a performance test for each pollutant for which it is subject to a standard at least once every 5 years. Dry low NO_X (DLN) combustion results in relatively stable emission rates. Furthermore, the DLN combustor is a fundamental part of a combustion turbine, and as long as similar maintenance procedures are followed, the Agency has concluded that emission rates will likely be comparable between similar combustion turbines. Therefore, the additional compliance costs associated with testing each affected turbine would not result in significant emissions reductions.

c. Verification of Proper Operation of Emission Controls

Turbine engine performance can deteriorate with operation and age. Operational parameters need to be verified periodically to ensure proper operation of emission controls. Therefore, the EPA is proposing in new subpart KKKKa to require facilities using the water- or steam-to-fuel ratio as a demonstration of continuous compliance with the NO_X emissions standard to verify the appropriate ratio or parameters at a minimum of every 60 months. The Agency has concluded this would not add significant burden since most affected facilities are already required to conduct performance testing at least every 5 years through title V requirements or other State permitting requirements.

d. Compliance for Multiple Turbine Engines With a Single HRSG

The existing NSPS (subpart KKKK) does not state how multiple combustion turbine engines that are exhausted through a single HRSG would demonstrate compliance with the NO_X standards. Therefore, the EPA is proposing in new subpart KKKKa and proposing to amend in subpart KKKK procedures for demonstrating compliance when multiple combustion turbine engines are exhausted through a single HRSG and when steam from multiple combustion turbine HRSGs is used in a single steam turbine. Furthermore, the existing rule requires approval from the permitting authority for any use of the part 75 NO_X monitoring provisions in lieu of the specified part 60 procedures, but the Agency's review has concluded that approval is an unnecessary burden for facilities only using combustion controls. Therefore, the EPA is proposing in new subpart KKKKa and proposing to amend in subpart KKKK to allow sources using only combustion controls to use the parametric NO_X monitoring in part 75 to demonstrate continuous compliance without requiring prior approval. However, if the source is using post-combustion control technology (*i.e.,* SCR) to comply with the requirements of the NSPS, then approval from the permitting authority is required prior to using the part 75 CEMS calibration procedures in place of the part 60 procedures.

F. Additional Request for Comments

1. Affected Facility

The EPA is considering and requesting comment on amending the definition of the affected facility in new subpart KKKKa for systems with multiple combustion turbine engines. Specifically, the Agency is requesting comment on treating multiple combustion turbine engines connected to a single generator, separate combustion turbines engines using a single HRSG, and separate combustion turbine engines with separate HRSG that use a single steam turbine or otherwise combine the useful thermal output as single affected facilities. This approach would reduce burden to the regulated community by simplifying monitoring. The EPA is also requesting comment on how the applicable emission standards would be determined and on how ''new'' and ''reconstruction'' would be defined in subpart KKKKa. The EPA is specifically requesting comment on basing the emission standards on either the base load rating of the largest single combustion turbine engine or the combined base load ratings of the combustion turbine engines. For an affected facility with multiple combustion turbine engines, the EPA is requesting comment on considering the entire facility ''new'' or ''reconstructed'' if any combustion turbine engine is replaced with a new combustion turbine engine or reconstructed.

2. District Energy

The EPA is considering and requesting comment on an appropriate method to recognize the environmental benefit of district energy systems in subpart KKKKa. The steam or hot water distribution system of a district energy system located in urban areas, college and university campuses, hospitals, airports, and military installations eliminates the need for multiple, smaller boilers at individual buildings. A central facility typically has superior emission controls and consists of a few larger boilers facilitating more efficient operation than numerous separate smaller individual boilers. However, when the hot water or steam is distributed, approximately 2 to 3 percent of the thermal energy in the water and 6 to 9 percent of the thermal energy in the steam is lost, reducing the net efficiency advantage. The EPA is requesting comment on whether it is appropriate in subpart KKKKa to divide the thermal output from district energy systems by a factor (*i.e.,* 0.95 or 0.90) that would account for the net efficiency benefits of district energy systems. This approach would be similar to how the electric output for CHP is considered when determining regulatory compliance. The EPA requests that comments include technical analysis of the net benefits in support of any conclusions.

3. Temporary Combustion Turbines

On occasion, owners/operators of industrial and commercial facilities or utilities need temporary combustion turbines for electric or direct mechanical energy production for short-term use while the primary generating equipment is not available, transmission is being repaired and/or upgraded, or for some other unforeseen event. These combustion turbines generally have a heat input of less than 250 MMBtu/h.[86] Both subpart KKKK and proposed subpart KKKKa apply to ''portable'' turbines and so these units would generally be covered by these subparts of the NSPS regulations if they meet other applicability criteria. Temporary turbines generally can be expected to use combustion control technology that limits NO_X emissions to rates of 25 ppm or lower. It is less clear whether SCR technologies are capable of being used in conjunction with temporary or portable combustion turbines. In addition, the permitting, testing, and monitoring requirements for a combustion turbine subject to an NSPS may not be appropriate or suitable for temporary combustion turbines. The need for temporary combustion turbines generally is a result of unforeseen events, and the permitting itself could take longer than the need for temporary generation. The EPA has historically considered engines or boilers in one location for less than a period of 180 days to 1 year to be temporary equipment not subject to regulation under their respective NSPS or NESHAP subparts.[87] The EPA is soliciting comment on whether an exemption, alternative emissions standards, and/or other streamlined requirements would be appropriate for temporary combustion turbines under subparts GG, KKKK, and KKKKa and the appropriate criteria for such regulatory provisions.

The EPA is soliciting comment on creating a subcategory for temporary combustion turbines, defined as turbines in one location for less than 1 year. Consistent with a BSER of combustion controls, this subcategory would be subject to a requirement for the owners or operators of such units to maintain records of manufacturer certification that the combustion turbine meets an emissions standard based on the use of combustion controls consistent with the otherwise applicable subcategory—25 or 15 ppm NO_X. This would be similar to the NSPS for Stationary Compression Ignition Internal Combustion Engines and the NSPS for Stationary Spark Ignition Internal Combustion Engines, which provide that temporary replacement units located at a stationary source for less than 1 year, and that have been properly certified as meeting the emissions standards that would be applicable to such engine under the appropriate nonroad engine provisions,

[86] At least one provider offers a portable combustion turbines that has base load rating greater than 250 MMBtu/h.

[87] See, for example, 40 CFR 60.4200(e), 60.4230(f), 60.40b(m), 60.40c(i), and 63.7491(j).

are not required to meet any other provisions under the NSPS with regard to such engine.[88] Under this approach, should a temporary combustion turbine remain in place for longer than 1 year, then it would not be considered temporary for *any* period of its operation, and any failure of the owner or operator to comply with the otherwise applicable requirements of the relevant subpart, even in the initial year of operation, would be an enforceable violation of the Act. In addition, under this approach, the EPA anticipates not allowing the replacement of a portable combustion turbine with another portable combustion turbine so as to maintain temporary status beyond a single year.

The EPA has believes that including such a provision in subpart KKKKa may be appropriate to allow for general maintenance, construction, temporary, and emergency power generation. The EPA further notes that, like temporary reciprocating engines, these units could replace other combustion turbines during periods where the main combustion turbines were off-line (*e.g.,* for maintenance work), owners/operators could have little or no ability to oversee the operations of these temporary combustion turbines, as they are generally owned and maintained by other entities. Therefore, the EPA solicits comment on whether it is appropriate to hold them to the requirements for similar sources that are portable in character. The EPA notes that adding this provision would specifically allow the use of temporary combustion turbines as an alternative to temporary reciprocating engines, which can have higher emission rates than combustion turbines.[89]

In the alternative, the EPA is soliciting comment on subcategorizing temporary combustion turbines using an approach the Agency has determined is appropriate for industrial boilers. The industrial boiler NSPS and NESHAP exempt temporary boilers that are capable of being moved from one location to another and are at a location for less than 180 days. While there is not a requirement for temporary boilers to meet any other requirements, the EPA is soliciting comment on whether it would be appropriate for the owner/operator of a temporary combustion turbine to conduct performance testing offsite and maintain records that indicate the combustion turbines are operating at emission rates at or below the NSPS emission standards in KKKKa. The requirements would be similar to those in the NSPS—annually or at least every 5 years depending on the specific situation.

4. 12-Calendar-Month NO_X Standard

The EPA is soliciting comment on adding a 12-calendar-month NO_X emissions limit as an alternative to subcategorizing combustion turbines based on capacity factor. The specific approach the Agency is considering is that new and reconstructed combustion turbines would be subject to the proposed short-term NO_X emissions standard (operating day or 4-hour rolling average).[90] For example, at high load operating conditions, the hourly standards would be 25 ppm and 15 ppm, respectively (assuming the combustion turbines are burning natural gas).[91] As an alternative to the short-term standards for combustion turbines operating at capacity factors of greater than 20 percent, all combustion turbines would also be subject to a 12-calendar-month emissions rate of 0.75 tons NO_X per MW of design capacity. This would have the impact of allowing simple cycle combustion turbines with NO_X emissions rate guarantees of 25 ppm to operate at a 12-calendar-month capacity factor of approximately 20 percent. Owners/operators that elect to operate at higher capacity factors would have to increase the efficiency of the unit by switching to a combined cycle unit, investing in combustion controls with lower NO_X emission rates, and/or using SCR.[92] Considering currently available combustion controls, owners/operators desiring the flexibility to operate as base load units would, as a practical matter, have to install SCR (or otherwise achieve comparable emissions performance). The EPA is considering, and soliciting comment on, a 12-calendar-month emissions rate range of 0.75 to 0.46 tons NO_X per MW of design capacity for the medium combustion turbine subcategory. The upper range is based on a highly efficient simple cycle turbine operating at the guaranteed NO_X performance rate of 25 ppm. The lower limit is based on a highly efficient simple cycle turbine operating at long-term typical emissions rate of 20 ppm NO_X and at a 12-calendar-month capacity factor of 15 percent. The annual standard for large combustion turbines based on performance guarantees is 0.45 tons of NO_X per MW of capacity. This value is based on a 15 ppm NO_X highly efficient simple cycle turbine operating at a capacity factor of 20 percent. Similar to the medium size subcategory, owners/operators that elect to operate at higher capacity factors would need to invest in some combination of higher efficiency, combustion controls with lower NO_X emission rates, and/or SCR. The EPA is considering, and soliciting comment on, a 12-calendar-month emissions rate range of 0.45 to 0.21 tons NO_X per MW of design capacity for the large combustion turbine subcategory. The lower limit is based on a highly efficient simple cycle turbine operating at long-term typical emissions rate of 7 ppm NO_X (the typical long-term emissions rate of a combustion turbine with a guaranteed emissions rate of 9 ppm NO_X) and at a 12-calendar-month capacity factor of 15 percent.

This approach recognizes the environmental benefit of efficiency—more efficient combustion turbines achieving the same input-based emissions rate (*e.g.,* lb NO_X/MMBtu) would be able to operate at higher capacity factors while still maintaining emissions below the annual standard. It also recognizes the environmental benefit of minimizing NO_X emissions during all periods of operation, including startup and shutdown, and reduces the regulatory incentive to switch to part-load operation so that the higher part-load standard is applicable during that hour. These environmental benefits could of course only be realized if two conditions were met: first, that the short-term limit remained in place, in addition to the long-term mass cap, thus ensuring a minimum level of good rate-based emissions performance at all times, and second, that the mass cap is calculated using accurate assumptions concerning the translation of a more stringent emissions rate associated, *e.g.,* with SCR operation, multiplied by an accurate estimate of overall operation. To the extent this approach could help achieve lower emissions overall while also avoiding the need to retrofit SCR control technology, it also provides an incentive for manufacturers to continue to improve combustion controls and the operating conditions over which the combustion controls can operate.

[88] 40 CFR 60.4200(e) and 60.4230(f).

[89] The NO_X emissions standard in table 1 to subpart JJJJ of part 60 for spark ignition natural gas-fired reciprocating engines greater than or equal to 500 HP is 82 ppmvd at 15 percent oxygen.

[90] A short-term mass based standard could also serve as an alternative to short-term standards based on lb NO_X/MMBtu. The basic rationale would be similar to the 12-calendar-month mass standard. For example, the 4-hour rolling mass standard would be 3.8 lb NO_X/MW and 2.3 lb NO_X/MW for the 25 ppm NO_X and 15 ppm NO_X subcategories, respectively.

[91] All other standards except the intermediate and base load NO_X standards would continue to be applicable.

[92] A 25 ppm NO_X combined cycle turbine or a 15 ppm simple cycle turbine would be able to operate up to an annual capacity factor of approximately 30 percent.

Additional benefits include lowering compliance costs and providing flexibility to the regulated community that is similar to conditions often included in operating permits. An annual emission limits recognizes the complex relationship between the choice of combustion controls (and the impact of those controls of other pollutants), the anticipated operation of the combustion turbine, and the use of SCR. The flexibility would allow the owner/operator of the combustion turbine to work with the permitting authority to determine the appropriate emissions reduction strategy for each specific project. The EPA requests comment, however, on a potential drawback of this approach, which is that owners/operators that install SCR that operate at lower than anticipated capacity factors could reduce the operation of the SCR, thus losing some environmental benefit that could otherwise have been cost effectively achieved.

5. System Emergency

The EPA included provisions that electricity sold during hours of operation when a unit is called upon due to a system emergency is not counted toward the percentage electric sales subcategorization thresholds in *Standards of Performance for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units* in 2015 and the final Carbon Pollution Standards earlier this year. *See* 40 CFR part 60, subparts TTTT and TTTTa.[93] In those rulemakings, the Agency concluded that this exclusion is necessary to provide flexibility, maintain system reliability, and minimize overall costs to the sector.[94] The EPA is soliciting comment on whether it is appropriate to add a similar provision for system emergencies to new subpart KKKKa that would apply to subcategories based on annual capacity factors. The EPA further solicits comment on defining system emergency in subpart KKKKa to mean ''periods when the Reliability Coordinator has declared an Energy Emergency Alert level 2 or 3 as defined by NERC Reliability Standard EOP–011–2 or its successor, or equivalent.'' This provision would ensure that combustion turbines intended for less frequent operation would be available for grid reliability purposes during grid emergencies without being subject to an emission standard that the unit might not be able to meet without an investment in additional controls. The EPA has determined it was necessary to add ''or equivalent'' for areas not covered by NERC Reliability Standard EOP–011–2, for example Puerto Rico. The definition would therefore differ slightly from the current definition in subpart TTTTa.

6. Exemptions in Subpart GG

The EPA included exemptions for combustion turbines used in certain military applications and firefighting applications from the standards of performance for gas turbines in 40 CFR part 60, subpart GG.[95] The EPA is soliciting comment on whether it is appropriate to include these exemptions from subpart GG in subparts KKKK and KKKKa. The exemptions include military combustion turbines for use in other than a garrison facility, military combustion turbines installed for use as military training facilities, and firefighting combustion turbines. These combustion turbines only operate during critical situations and the EPA is soliciting comment on whether requiring advanced combustion controls could impact reliability or otherwise impact the ability of the combustion turbines to serve the intended purpose.

7. Exemption of Certain Low-Emitting Facilities From Title V Permitting

The EPA is soliciting comment on whether it would be appropriate to exempt certain low-emitting stationary combustion turbines subject to subparts GG, KKKK, or new subpart KKKKa from title V permitting requirements under CAA section 502(a). According to section 502(a), the EPA may exempt certain sources subject to CAA section 111 (NSPS) standards from the requirements of title V if the EPA finds that compliance with such requirements is ''impracticable, infeasible, or unnecessarily burdensome'' on such sources. However, CAA 502(a) further states that ''. . . the Administrator may not exempt any major source from such requirements.'' Thus, any exemption from title V permitting under this provision cannot extend to any sources that are ''major sources'' as that term is defined at CAA section 501(2). The EPA has previously established permitting exemptions under this provision for several NSPS, particularly in circumstances where the affected facilities are numerous and individually relatively low-emitting, the burdens and process of obtaining permits would be overwhelming for permitting authorities and the sources (such as numerous small businesses, farms, or residences), and where compliance with the emissions standards can be assured through the manufacture or design of the equipment or facility in question.[96]

At this time, the EPA has not determined that title V permitting is ''impracticable, infeasible, or unnecessarily burdensome'' for sources subject to subparts GG, KKKK, or KKKKa, and the EPA is not proposing to exempt any such sources from title V permitting.

However, the EPA requests comment to better understand whether there are circumstances in which the burdens and costs of going through title V permitting, for sources, permitting authorities, and other stakeholders and the public, would not be justified in light of the purposes of title V to improve compliance with the Act's applicable requirements, to provide transparency to the public concerning the location and operation of stationary sources of air pollution, and to ensure public participation in the process of permitting the operation of such sources. The EPA specifically requests comment on whether there are appropriate size-, emissions-, or other characteristics that could be appropriately used to define sources that may warrant exemption under CAA section 502(a), and what specific features of these sources would justify such an exemption in light of the statutory criteria.

A memo from the EPA's 2012 NSPS Proposal describing the proposed section 502(a) exemption from title V permitting requirements for non-major stationary combustion turbines subject to subparts GG or KKKK is available in the rulemaking docket.

G. Proposal of NSPS Subpart KKKKa Without Startup, Shutdown, Malfunction Exemptions

In its 2008 decision in *Sierra Club* v. *EPA,* 551 F.3d 1019 (D.C. Cir. 2008), the United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit) vacated portions of two provisions in the EPA's CAA section 112 regulations governing the emissions

[93] See 40 CFR 60.5580 and 60.5580a.

[94] See 80 FR 64612 (October 23, 2015) and 89 FR 39914–15 (May 9, 2024).

[95] See 40 CFR 60.332(g).

[96] See, for example, 40 CFR 60.4200(c) (''If you are an owner or operator of an area source subject to this subpart, you are exempt from the obligation to obtain a permit under 40 CFR part 70 or 40 CFR part 71, provided you are not required to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a) for a reason other than your status as an area source under this subpart.'') and 40 CFR 70.3(b)(4)(i) (''The following source categories are exempted from the obligation to obtain a part 70 permit: All sources and source categories that would be required to obtain a permit solely because they are subject to part 60, subpart AAA—Standards of Performance for New Residential Wood Heaters'').

of HAP during periods of SSM. Specifically, the court vacated the SSM exemption contained in 40 CFR 63.6(f)(1) and (h)(1), holding that under section 302(k) of the CAA, emissions standards or limitations must be continuous in nature and that the SSM exemption violates the CAA's requirement that some section 112 standards apply continuously. The EPA has determined the reasoning in the court's decision in Sierra Club applies equally to CAA section 111 because the definition of ''emission standard'' in CAA section 302(k), and the embedded requirement for continuous standards, also applies to the NSPS. Consistent with *Sierra Club* v. *EPA,* we are proposing that standards in subpart KKKKa apply at all times.

The NSPS general provisions in 40 CFR 60.11(c) currently exclude opacity requirements during periods of startup, shutdown, and malfunction (SSM) and the provision in 40 CFR 60.8(c) contains an exemption from non-opacity standards. We are proposing in subpart KKKKa specific requirements at 40 CFR 60.420a(e) that override the general provisions for SSM provisions.

The EPA has attempted to ensure that the general provisions we are proposing to override are inappropriate, unnecessary, or redundant in the absence of the SSM exemption. We are specifically seeking comment on whether we have successfully done so.

In proposing the standards in this rulemaking, the EPA has taken into account startup and shutdown periods and, for the reasons explained in this section of the preamble, has not proposed alternate standards for those periods other than possible alternative NO_X standards during startup of stationary combustion turbines. As discussed in more detail in section III.B.16.a., we are requesting comment on whether to account for startup conditions based on differences in load during the first 30 minutes of operation.

Periods of startup, normal operations, and shutdown are all predictable and routine aspects of a source's operations. Malfunctions, in contrast, are neither predictable nor routine. Instead, they are, by definition, sudden, infrequent, and not reasonably preventable failures of emissions control, process, or monitoring equipment (40 CFR 60.2). The EPA interprets CAA section 111 as not requiring emissions that occur during periods of malfunction to be factored into development of CAA section 111 standards. Nothing in CAA section 111 or in case law requires that the EPA consider malfunctions when determining what standards of performance reflect the degree of emission limitation achievable through ''the application of the best system of emission reduction'' that the EPA determines is adequately demonstrated. While the EPA accounts for variability in setting emissions standards, nothing in CAA section 111 requires the Agency to consider malfunctions as part of that analysis. The EPA is not required to treat a malfunction in the same manner as the type of variation in performance that occurs during routine operations of a source. A malfunction is a failure of the source to perform in a ''normal or usual manner'' and no statutory language compels the EPA to consider such events in setting CAA section 111 standards of performance. The EPA's approach to malfunctions in the analogous circumstances (setting ''achievable'' standards under CAA section 112) has been upheld as reasonable by the D.C. Circuit in *U.S. Sugar Corp.* v. *EPA,* 830 F.3d 579, 606–610 (D.C. Cir. 2016).

H. Testing and Monitoring Requirements

Owners/operators of affected sources that (1) use water or steam injection and (2) elect not to use a NO_X CEMS, must then continuously monitor the water- or steam-to-fuel ratio of the affected source to demonstrate compliance. This requires the installation and operation of a continuous monitoring system that monitors and records both the fuel consumption and the ratio of water- or steam-to-fuel being fired in the turbine. Owners/operators of affected combustion turbines using dry combustion controls that elect not to use a NO_X CEMS must conduct performance testing at a minimum of every 5 years. Owners/operators of combustion turbines using SCR must use a NO_X CEMS to demonstrate compliance with the applicable emissions standards (owners/operators of combustion turbines not using SCR may elect to use a NO_X CEMS as an alternative to the otherwise required monitoring).

I. Electronic Reporting

The EPA is proposing that owners and operators of stationary combustion turbine facilities subject to NSPS subparts GG and KKKK, and the proposed new subpart KKKKa, submit electronic copies of the initial and periodic performance test reports, CEMS performance evaluation reports (including relative accuracy test audits), and compliance reports through the EPA's Central Data Exchange (CDX) using the Compliance and Emissions Data Reporting Interface (CEDRI). A description of the electronic data submission process is provided in the memorandum *Electronic Reporting Requirements for New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAP) Rules,* available in the docket for this action. The proposed rule requires that performance test results collected using test methods that are supported by the EPA's Electronic Reporting Tool (ERT) as listed on the ERT website [97] at the time of the test be submitted in the format generated through the use of the ERT or an electronic file consistent with the xml schema on the ERT website, and other performance test results be submitted in portable document format (PDF) using the attachment module of the ERT. Similarly, performance evaluation results of continuous emissions monitoring systems (CEMS) measuring relative accuracy test audit (RATA) pollutants that are supported by the ERT at the time of the test must be submitted in the format generated through the use of the ERT or an electronic file consistent with the xml schema on the ERT website, and other performance evaluation results be submitted in PDF using the attachment module of the ERT.

Specifically, the proposed rule requires that (1) for NSPS subpart GG, the reports specified in 40 CFR 60.334, (2) for NSPS subpart KKKK, the reports specified in 40 CFR 60.4375, and (3) for NSPS subpart KKKKa, the reports specified in 40 CFR 60.4375a, owners and operators use the appropriate spreadsheet template to submit information to CEDRI. A draft version of the proposed template(s) for these reports is included in the docket for this action.[98] The EPA specifically requests comment on the content, layout, and overall design of the template(s).

Additionally, the EPA has identified two broad circumstances in which electronic reporting extensions may be provided. These circumstances are (1) Outages of the EPA's CDX or CEDRI, which preclude an owner or operator from accessing the system and submitting the required reports and (2) *force majeure* events, which are defined as events that will be or have been caused by circumstances beyond the control of the affected facility, its contractors, or any entity controlled by the affected facility that prevent an owner or operator from complying with the requirement to submit a report electronically. Examples of *force majeure* events are acts of nature, acts of war or terrorism, or equipment failure

[97] See *https://www.epa.gov/electronic-reporting-air-emissions/electronic-reporting-tool-ert.*

[98] See Docket ID. No. EPA–HQ–OAR–2024–0419.

or safety hazards beyond the control of the facility. The EPA is providing these potential extensions to protect owners and operators from noncompliance in cases where they cannot successfully submit a report by the reporting deadline for reasons outside of their control. In both circumstances, the decision to accept the claim of needing additional time to report is within the discretion of the Administrator, and reporting should occur as soon as possible.

The electronic submittal of the reports addressed in this proposed rulemaking will increase the usefulness of the data contained in those reports, is in keeping with current trends in data availability and transparency, will further assist in the protection of public health and the environment, will improve compliance by facilitating the ability of regulated facilities to demonstrate compliance with requirements and by facilitating the ability of delegated State, local, Tribal, and territorial air agencies and the EPA to assess and determine compliance, and will ultimately reduce burden on regulated facilities, delegated air agencies, and the EPA. Electronic reporting also eliminates paper-based, manual processes, thereby saving time and resources, simplifying data entry, eliminating redundancies, minimizing data reporting errors, and providing data quickly and accurately to the affected facilities, air agencies, the EPA, and the public. Moreover, electronic reporting is consistent with the EPA's plan [99] to implement Executive Order 13563 and is in keeping with the EPA's agency-wide policy [100] developed in response to the White House's Digital Government Strategy.[101] For more information on the benefits of electronic reporting, see the memorandum *Electronic Reporting Requirements for New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAP) Rules,* referenced earlier in this section.

J. Compliance Dates

Pursuant to CAA section 111(b)(1)(B), the effective date of the final rule requirements in subpart KKKKa will be the promulgation date. Affected sources that commence construction, reconstruction, or modification after December 13, 2024 must comply with all requirements of subpart KKKKa, no later than the effective date of the final rule or upon startup, whichever is later.

K. Severability

This proposed action contains several discrete components, which the EPA views as severable as a practical matter—*i.e.,* they are functionally independent and if finalized as proposed would operate in practice independently of the other components. These discrete components are generally delineated by the section headings within this section III of this document. In general, each of the proposed BSER determinations and associated emissions standards for each subcategory function independently of the others, as do any differences in the proposed rule associated with modified or reconstructed units. In addition, the several other proposed changes to subparts GG and KKKK and the associated proposals for new subpart KKKKa generally function independently of one another. The EPA invites comment on the severability of this proposed rule, and in particular whether any components are not functionally independent, and if not, why not.

IV. Summary of Cost, Environmental, and Economic Impacts

A. What are the air quality impacts?

During the period 2025–2032, the EPA estimates that approximately 251 new stationary combustion turbines will be installed in the U.S. and would be affected by this rule, as proposed. The EPA estimates that 153 of these combustion turbines will be in the electric utility power sector. For affected combustion turbines in the electric utility power sector, the proposed BSER in subpart KKKKa is generally consistent with the control technologies in the baseline. That is, based on data reported to the EPA, the Agency anticipates that new combined cycle facilities (including combined cycle CHP facilities) would already have plans to install the controls proposed in this NSPS, though in some cases it is expected that the combined cycle turbines would have to upgrade and/or operate the controls more intensively to meet the proposed NSPS requirements in new subpart KKKKa. The EPA estimates the majority of new simple cycle combustion turbines generating electricity would be in the low load subcategory and have combustion controls consistent with the proposed standards and would not be impacted by the proposal. Approximately 10 percent of simple cycle turbines would operate as intermediate load combustion turbines, but based on the historical baseline, these combustion turbines would already have SCR. It is expected that the intermediate load simple cycle EGUs would have to upgrade and/or operate their NO_X controls more intensively to meet the proposed NSPS requirements in new subpart KKKKa. The EPA anticipates that none of the five new non-combined cycle CHP turbines [102] would have SCR in the baseline and would have to install SCR to comply with the proposed emission standards.[103] Relative to the historic baseline, the proposed emission standards would result in approximately 30 utility units being expected to incur additional costs under the proposed NSPS requirements in subpart KKKKa. Based on information in Form EIA–860 and a review of permits, the EPA anticipates that 30 new small EGUs will be built during the analysis period. Six of these combustion turbines would be low load units and would be expected to install combustion controls in the baseline consistent with the proposed emission standards. The EPA estimates that the remaining 24 combustion turbines would be base load CHP facilities and that the proposed BSER of combustion controls in combination with SCR would apply. Furthermore, according to the data, four facilities would have SCR in the baseline with permitted emission rates consistent with the proposed emission standards in subpart KKKKa and thus would not be impacted. However, one facility with SCR would need to upgrade its SCR equipment to comply with the proposed NO_X standards. The remaining 19 small CHP facilities do not have SCR in the baseline.

Based on information collected as part of the proposed combustion turbine NESHAP rulemaking as discussed previously in sections II.D and III.D.3, the EPA projects 52 direct mechanical drive combustion turbines (*e.g.,* compressors) would be subject to the proposed NO_X standards in subpart KKKKa. The EPA estimates that all 52

[99] EPA's Final Plan for Periodic Retrospective Reviews, August 2011. Available at: *https://www.regulations.gov/document?D=EPA-HQ-OA-2011-0156-0154.*

[100] E-Reporting Policy Statement for EPA Regulations, September 2013. Available at: *https://www.epa.gov/sites/default/files/2016-03/documents/epa-ereporting-policy-statement-2013-09-30.pdf.*

[101] Digital Government: Building a 21st Century Platform to Better Serve the American People, May 2012. Available at *https://obamawhitehouse.archives.gov/sites/default/files/omb/egov/digital-government/digital-government.html.*

[102] Non-combined cycle CHP turbines include a combustion turbine engine and a HRSG and all the useful thermal output is used for heating applications and not to generate additional electricity (*i.e.,* the facility does not have a steam turbine). These facilities are sometimes referred to as simple cycle CHP turbines. Combined cycle CHP turbines use a portion of the energy in the steam to generate additional electricity and a portion for heating applications.

[103] Three of the CHP facilities without a steam turbine are not listed in CAMPD.

of these units would operate as base load combustion turbines and would be subject to the proposed NO_X emission standards in subpart KKKKa based on application of the BSER of combustion controls in combination with SCR. None of these 52 combustion turbines have SCR in the baseline and would be projected to install SCR to comply with the proposed emission standards. In total, this proposed rule is estimated to reduce NO_X emissions by 198 tons in 2027; 714 tons in 2028; 1,229 tons in 2029; 1,744 tons in 2030; 2,259 tons in 2031; and 2,659 tons in 2032. There are no expected SO_2 reductions as a result of the rule, as proposed. All emissions reductions estimates and assumptions have been documented in the docket to the proposed rule.

B. What are the secondary impacts?

The requirements in new subpart KKKKa are not anticipated to result in significant energy impacts. The only energy requirement is a potential small increase in fuel consumption, resulting from operating the NO_X control equipment and back pressure caused by an add-on emission control device, such as an SCR. However, certain entities would be able to comply with the proposed rule without the use of add-on control devices. The EPA is soliciting comment on whether the proposed requirements would result in fewer new combustion turbines being constructed, modified, or reconstructed and if that would result in increased generation from existing EGUs, including coal-fired EGUs, or greater reliance on reciprocating engines to meet energy needs. However, because the cost of combustion controls and SCR is a relatively small percentage of the total costs associated with building and operating combustion turbines, the EPA does not anticipate significant secondary effects in terms of switching to other methods of electricity generation or mechanical output.

The increased application of SCR is estimated to increase emissions of ammonia (NH_3) and carbon dioxide (CO_2). Therefore, proposed subpart KKKKa is estimated to increase NH_3 emissions by 21 tons in 2027; 65 tons in 2028; 108 tons in 2029; 152 tons in 2030; 196 tons in 2031; and 232 tons in 2032. CO_2 emissions are estimated to increase by 1,597 tons in 2027; 4,921 tons in 2028; 8,244 tons in 2029; 11,568 tons in 2030; 14,891 tons in 2031; and 17,680 tons in 2032.

C. What are the cost impacts?

To comply with the requirements of this proposed rule, some units will incur capital costs associated with installation of SCR or upgrades to existing controls, while some units are expected to incur increased operating costs of their existing controls to meet the proposed requirements. These capital and increased operating costs were estimated based on model plants from the DOE NETL flexible generation report.[104] For the analysis period 2025–2032, the present value of the expected costs of the proposed rule is approximately $166 million (2023$), while the equivalent annualized value of the costs over the analysis period is $22.6 million (2023$).

D. What are the economic impacts?

Economic impact analyses focus on changes in market prices and output levels. If changes in market prices and output levels in the primary markets are significant enough, impacts on other markets may also be examined. Both the magnitude of costs needed to comply with a rule and the distribution of these costs among affected facilities can have a role in determining how the market will change in response to a rule.

This proposed rule requires new, modified, or reconstructed stationary combustion turbines to meet emission standards for the release of NO_X into the environment. While the units impacted by these requirements are expected to already have installed any required emissions control devices, some units are expected to incur increased operating costs of their existing controls to meet the proposed requirements. These changes may result in higher costs of production for affected producers and impact broader product markets if these costs are transmitted through market relationships.

However, because the increased operating costs discussed in the previous section are very small in comparison to the sales of the average owner of a combustion turbine, the costs of this proposed rule are not expected to result in a significant market impact, regardless of whether they are passed on to through market relationships or absorbed by the firms. For more information on these impacts, please refer to the economic impact analysis in the public docket.

E. What are the benefits?

Combustion turbines are a source of NO_X and SO_2 emissions. The health effects of exposure to these pollutants are briefly discussed in this section. Because the proposed NSPS is expected to result in reductions of NO_X emissions, the EPA estimated the monetized benefits related to avoided premature mortality and morbidity associated with reduced exposure to NO_X as a precursor to ozone and $PM_{2.5}$ using a ''benefit-per-ton'' (BPT) approach.[105] These results are summarized below.

1. Benefits of NO_X Reductions

Nitrogen dioxide (NO_2) is the criteria pollutant that is central to the formation of nitrogen oxides (NO_X), and NO_X emissions are a precursor to ozone and fine particulate matter.[106]

Based on many recent studies discussed in the ozone ISA,[107] the EPA has identified several key health effects that may be associated with exposure to elevated levels of ozone. Exposures to high ambient ozone concentrations have been linked to increased hospital admissions and emergency room visits for respiratory problems. Repeated exposure to ozone may increase susceptibility to respiratory infection and lung inflammation and can aggravate preexisting respiratory disease, such as asthma. Prolonged exposures can lead to inflammation of the lung, impairment of lung defense mechanisms, and irreversible changes in lung structure, which could in turn lead to premature aging of the lungs and/or chronic respiratory illnesses such as emphysema, chronic bronchitis, and asthma.

Children typically have the highest ozone exposures since they are active outside during the summer when ozone levels are the highest. Further, children are more at risk than adults from the effects of ozone exposure because their respiratory systems are still developing. Adults who are outdoors and moderately active during the summer months, such as construction workers and other outdoor workers, also are among those with the highest exposures. These individuals, as well as people with respiratory illnesses such as asthma, especially children with asthma, experience reduced lung function and increased respiratory symptoms, such as chest pain and cough, when exposed to relatively low

[104] Oakes, M.; Konrade, J.; Bleckinger, M.; Turner, M.; Hughes, S.; Hoffman, H.; Shultz, T.; and Lewis, E. (May 5, 2023). *Cost and Performance Baseline for Fossil Energy Plants, Volume 5: Natural Gas Electricity Generating Units for Flexible Operation.* U.S. Department of Energy (DOE). Office of Scientific and Technical Information (OSTI). Available at *https://www.osti.gov/biblio/1973266.*

[105] See *https://www.epa.gov/benmap/sector-based-pm25-benefit-ton-estimates* and *https://www.epa.gov/system/files/documents/2024-06/source-apportionment-tsd-2024.pdf.*

[106] Additional information is available in the ISA at *https://www.epa.gov/isa/integrated-science-assessment-isa-oxides-nitrogen-health*-criteria.

[107] See Ozone ISA at *https://assessments.epa.gov/isa/document/&deid=348522.*

ozone levels during periods of moderate exertion.

NO_X emissions can react with ammonia, VOCs, and other compounds to form $PM_{2.5}$.[108] Studies have linked $PM_{2.5}$ (alone or in combination with other air pollutants) with a series of negative health effects. Short-term exposure to $PM_{2.5}$ has been associated with premature mortality, increased hospital admissions, bronchitis, asthma attacks, and other cardiovascular outcomes. Long-term exposure to $PM_{2.5}$ has been associated with premature death, particularly in people with chronic heart or lung disease. Children, the elderly, and people with cardiopulmonary disease, such as asthma, are most at risk from these health effects.

Reducing the emissions of NO_X from stationary combustion turbines can help to improve some of the effects mentioned above, either those directly related to NO_X emissions, or the effects of ozone and $PM_{2.5}$ resulting from the combination of NO_X with other pollutants.

To estimate the monetized benefits of the NO_X emission reductions associated with this rulemaking, we multiplied the BPT estimates for the industrial boilers sector by the corresponding emission decreases expected from this proposed rule. Since EPA does not have BPT values for the combustion turbines sector, EPA chose a surrogate sector, industrial boilers, for the calculations. Industrial boilers were chosen because both turbines and boilers generally fire natural gas, and both have NO_X controls, and vent to the atmosphere through a stack. Since, since this proposed rule is an NSPS, we do not know where the new turbines will be located. Therefore, we used the national average BPT values for the industrial boilers BPT sector and multiplied it by the emissions values. However, EPA acknowledges the limitations of using surrogate sectors for BPT estimations.

The benefit-per-ton estimates comprise several point estimates of mortality and morbidity. The two benefits estimates are separated by the word ''and'' to signify that they are two separate estimates and do not represent lower- and upper-bound estimates. Because NO_X contributes to the formation of both $PM_{2.5}$ and ozone, there are two sets of BPT estimates for NO_X, and these are added together in the analysis. Considering that the estimated NO_X emission reductions from this rulemaking are annual, we estimated the whole year with NO_X as a $PM_{2.5}$ precursor, then as a 5-month seasonal precursor to ozone to simulate the warmer months. Also, since some of the ammonia used in the SCR for NO_X reduction passes through the SCR and is emitted, we include NH_3 disbenefits in the health effects estimation.

For the proposed rule, the lower estimate of the present value in 2024 of the monetized NO_X emission reductions is $200 million at a 2 percent discount rate, while the upper estimate is $670 million. The equivalent annualized value of the lower estimate is $27 million at a 2 percent discount rate, while the upper estimate is $92 million. All estimates are reported in 2023 dollars.

The EPA recognizes the uncertainty introduced by the use of the BPT estimate based on industrial boilers. The EPA also has calculated the value of NO_X emissions reductions based on BPTs from two alternative sectors: electricity generating units (EGUs) and oil and gas transmission. Based on the EGU-based BPT, the lower estimate of the present value in 2024 of the monetized NO_X emission reductions is $150 million at a 2 percent discount rate while the upper estimate is $750 million. The equivalent annualized value of the lower estimate is $21 million at a 2 percent discount rate while the upper estimate is $100 million. Based on the oil and gas transmission-based BPT, the lower estimate of the present value in 2024 of the monetized NO_X emission reductions is $180 million at a 2 percent discount rate while the upper estimate is $620 million. The equivalent annualized value of the lower estimate is $24 million at a 2 percent discount rate while the upper estimate is $84 million.

2. Benefits of SO_2 Reductions

High concentrations of sulfur dioxide (SO_2) can cause inflammation and irritation of the respiratory system, especially during physical activity.[109] Exposure to very high levels of SO_2 can lead to burning of the nose and throat, breathing difficulties, severe airway obstruction, and can be life threatening. Long-term exposure to persistent levels of SO_2 can lead to changes in lung function.

Sensitive populations include asthmatics, individuals with bronchitis or emphysema, children, and the elderly. PM can also be formed from SO_2 emissions. Secondary PM is formed in the atmosphere through a number of physical and chemical processes that transform gases, such as SO_2, into particles. Overall, emissions of SO_2 can lead to some of the effects discussed in this section—either those directly related to SO_2 emissions, or the effects of PM resulting from the combination of SO_2 with other pollutants. Proposing to maintain the standards of performance for emissions of SO_2 from all stationary combustion turbines would continue to protect human health and the environment from the adverse effects mentioned above.

3. Disbenefits From Increased Emissions of NH_3 and CO_2

Ammonia is a precursor to $PM_{2.5}$ formation and an increase in NH_3 formation may lead to an increase in $PM_{2.5}$. An increase in $PM_{2.5}$ is associated with significant mortality and morbidity health outcomes such as premature mortality, stroke, lung cancer, metabolic and reproductive effects, among others. The estimated ammonia disbenefits were estimated using the ammonia emission increases reported above with the same BPT approach used for NO_X based on applying a proxy sector BPT value. For the proposed rule, the lower estimate of the present value in 2024 of the monetized NH_3 disbenefits is $76 million at a 2 percent discount rate, while the upper estimate is $160 million. The equivalent annualized value of the lower estimate is $10 million at a 2 percent discount rate, while the upper estimate is $21 million. All estimates are reported in 2023 dollars.

The climate impacts of the CO_2 emissions increases expected from this proposed rule were monetized using estimates of the social cost of greenhouse gases. For this proposed rule, the present value in 2024 of the monetized CO_2 emission increases is $12.6 million at a 2 percent discount rate, and the equivalent annualized value is $1.72 million at a 2 percent discount rate. These estimates are reported in 2023 dollars.

F. What analysis of environmental justice did we conduct?

For purposes of analyzing regulatory impacts, the EPA relies upon its June 2016 ''Technical Guidance for Assessing Environmental Justice in Regulatory Analysis,'' which provides recommendations that encourage analysts to conduct the highest quality analysis feasible, recognizing that data limitations, time, resource constraints, and analytical challenges will vary by media and circumstance. The Technical Guidance states that a regulatory action

[108] $PM_{2.5}$ health effects are discussed in detail in the ISA at *https://www.epa.gov/isa/integrated-science-assessment-isa-particulate-matter.*

[109] Health effects are discussed in detail in the ISA available at *https://www.epa.gov/isa/integrated-science-assessment-isa-sulfur-oxides-health-criteria.*

may involve potential EJ concerns if it could: (1) Create new disproportionate impacts on communities with EJ concerns; (2) exacerbate existing disproportionate impacts on communities with EJ concerns; or (3) present opportunities to address existing disproportionate impacts on communities with EJ concerns through this action under development. The EPA's EJ technical guidance states that ''[t]he analysis of potential EJ concerns for regulatory actions should address three questions: (A) Are there potential EJ concerns associated with environmental stressors affected by the regulatory action for population groups of concern in the baseline? (B) Are there potential EJ concerns associated with environmental stressors affected by the regulatory action for population groups of concern for the regulatory option(s) under consideration? (C) For the regulatory option(s) under consideration, are potential EJ concerns created or mitigated compared to the baseline?'' [110] The environmental justice analysis is presented for the purpose of providing the public with as full as possible an understanding of the potential impacts of this proposed action. The EPA believes that analyses like this can inform the public's understanding, place EPA's action in context, and help, identify and illustrate the extent of potential burdens and protections. The EPA notes that analysis of such impacts is distinct from the determinations proposed in this action under CAA section 111, which are based solely on the statutory factors the EPA is required to consider under that section.

The locations of newly constructed sources that will become subject to the proposed Stationary Combustion Turbines and Stationary Gas Turbines NSPS (40 CFR part 60, subpart KKKKa) are not known. Therefore, to examine the potential for any EJ issues that might be associated with the proposed NSPS, we performed a proximity demographic analysis for 130 existing facilities that are currently subject to NSPS subpart KKKK that have been constructed in the past five years. These represent facilities that might modify or reconstruct in the future and become subject to the proposed KKKKa requirements. This proximity demographic analysis characterized the individual demographic groups of the populations living within 5 km (~3 miles) and within 50 km (~31 miles) of the existing facilities. The 5 km radius was used for the near proximity because it captures a large enough population to provide demographic data without excessive uncertainty for most facilities. We do note, however, that one facility has zero population living within 5 km and another two facilities have less than 100 people living within 5 km. The EPA then compared the data from this analysis to the national average for each of the demographic groups. It should be noted that proximity to affected facilities does not indicate that any exposures or impacts will occur and should not be interpreted as a direct measure of exposure or impact. This limits the usefulness of proximity analyses when attempting to answer questions from the EPA's EJ Technical Guidance. The results of the proximity demographic analysis are shown in Table 2 of this preamble. The percent of the population living within 5 km of existing facilities with stationary combustion turbines is above the national average for the following racial/ethnicity demographics: Black (14 percent versus 12 percent nationally), Hispanic/Latino (20 percent versus 19 percent nationally), and Asian (9 percent versus 6 percent nationally). In addition, the percent of population living within 5 km of the existing facilities with stationary combustion turbines is above the national average for the following demographics: people living below the poverty level (15 percent versus 13 percent nationally), people living below two times the poverty level (30 percent versus 29 percent nationally), linguistic isolation (6 percent versus 5 percent nationally), and people with one or more disabilities (13 percent versus 12 percent nationally). The percent of the population living within 50 km of existing facilities with stationary combustion turbines is above the national average for the following racial/ethnicity demographics: Black (14 percent versus 12 percent nationally), Hispanic/Latino (22 percent versus 19 percent nationally), and Asian (7 percent versus 6 percent nationally). In addition, the percent of population living within 50 km of existing facilities with stationary combustion turbines and stationary gas turbines is above the national average for linguistic isolation (7 percent versus 5 percent nationally) and people with one or more disabilities (13 percent versus 12 percent nationally).

TABLE 2—PROXIMITY DEMOGRAPHIC ASSESSMENT RESULTS FOR STATIONARY COMBUSTION TURBINES NSPS

Demographic group	Nationwide	Population within 50 km of 130 facilities	Population within 5 km of 130 facilities
Total Population	334,369,975	145,990,767	6,177,476
	Race and Ethnicity by Percent		
White	58	52	52
Black	12	14	14
American Indian and Alaska Native	0.5	0.2	0.3
Asian	6	7	9
Hispanic or Latino (white and nonwhite)	19	22	20
Other and Multiracial	4	4	4
	Age by Percent		
Age 0 to 17 years	22	21	19
Age 18 to 64 years	61	62	67
Age ≥ 65 years	17	16	14

[110] U.S. Environmental Protection Agency (EPA). (June 2016). *Technical Guidance for Assessing Environmental Justice in Regulatory Analysis.* Section 3. Page 11. Available at *https://www.epa.gov/environmentaljustice/technical-guidance-assessing-environmental-justice-regulatory-analysis.*

TABLE 2—PROXIMITY DEMOGRAPHIC ASSESSMENT RESULTS FOR STATIONARY COMBUSTION TURBINES NSPS—Continued

Demographic group	Nationwide	Population within 50 km of 130 facilities	Population within 5 km of 130 facilities
	Income by Percent		
Below Poverty Level	13	12	15
Below 2x Poverty Level	29	27	30
	Education by Percent		
Over 25 and without a High School Diploma	11	11	10
	Linguistically Isolated by Percent		
Linguistically Isolated	5	7	6
	Disabilities by Percent		
People with One or More Disabilities	12	13	13

Notes:

- The demographic percentages are based on the 2020 Decennial Census' block populations, which are linked to the Census' 2018–2022 American Community Survey (ACS) five-year demographic averages at the block group or tract level. To derive demographic percentages, it is assumed a block's demographics are the same as the block group or tract in which it is contained. Demographics are tallied for all blocks falling within the indicated radius.
- To avoid double counting, the ''Hispanic or Latino'' category is treated as a distinct demographic category for these analyses. A person is identified as one of six racial/ethnic categories above: White, Black, American Indian or Alaska Native, Asian, Other and Multiracial, or Hispanic/Latino. A person who identifies as Hispanic or Latino is counted as Hispanic/Latino for this analysis, regardless of what race this person may have also identified as in the Census.

As indicated above, the locations of any new stationary combustion turbines that would be subject to NSPS subpart KKKKa are not known. In addition, it is not known which existing turbines may be modified or reconstructed and subject to NSPS subpart KKKKa. Thus, we are limited in our ability to estimate the potential EJ impacts of this rulemaking. However, we anticipate the changes to NSPS subpart KKKKa will generally minimize future emissions in surrounding communities of new, modified, or reconstructed turbines. Specifically, the EPA is proposing that the standards should be revised downward based on the identification of SCR as the BSER for limiting NO_X for certain larger and/or higher operating combustion turbines and based on updated information concerning improved combustion control performance at all combustion turbines firing natural gas. The changes will have beneficial effects on air quality and public health for populations exposed to emissions from new, modified, or reconstructed stationary combustion turbines and will provide additional health protection for most populations, including communities with EJ concerns.

The methodology and the results (including facility-specific results) of the demographic analysis are presented in the document titled *Analysis of Demographic Factors for Populations Living Near Existing Facilities Subject to the Stationary Combustion Turbines and Stationary Gas Turbines NSPS (Subpart KKKK and KKKKa),* which is available in the docket for this action.

V. Statutory and Executive Order Reviews

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

A. Executive Order 12866: Regulatory Planning and Review and Executive Order 14094: Modernizing Regulatory Review

This proposed NSPS is a ''significant regulatory action'' as defined in Executive Order 12866, as amended by Executive Order 14094. Accordingly, the EPA submitted this proposed rule to OMB for Executive Order 12866 review. Documentation of any changes made in response to the Executive Order 12866 review is available in the docket. The EPA prepared an economic analysis of the potential impacts associated with this action. This analysis is discussed in section IV of this preamble and is also available in the docket.

The RIA estimates the costs and monetized human health benefits from 2025–2032 associated with the application of the proposed BSER to stationary combustion turbines with a heat input at peak load equal to or greater than 10.7 GJ/h (10 MMBtu/h), based on the higher heating value (HHV) of the fuel, that commence construction, modification, or reconstruction after the date of publication of this proposed rule in the **Federal Register**. These costs and monetized human health benefits are relative to the baseline of the existing NSPS (subpart KKKK). Table 3 below provides a summary of the estimated monetized benefits, costs, and net benefits associated with the application of the proposed BSER to these new, modified, or reconstructed stationary combustion turbines and stationary gas turbines.

TABLE 3—ESTIMATED MONETIZED BENEFITS, COSTS, DISBENEFITS, NON-MONETIZED IMPACTS, AND NET BENEFITS OF PROPOSED COMBUSTION TURBINES NSPS

Costs and benefits	Present value (PV) (2 percent discount rate in millions of 2023$)	Equivalent annualized value (EAV) (2 percent discount rate in millions of 2023$)
Monetized benefits	$195 and $674	$26.7 and $92.0.
Alternative calculation of monetized benefits	$150 and $750	$21 and $100.
Total annual costs	$166	$22.6.
Monetized disbenefits	$88.4 and $169	$12.1 and $23.0.
Non-monetized impacts	Any other climate, health, and environmental impacts or costs associated with increased use of existing emissions controls, including non-monetized impacts of NO_X and NH_3 as well as effects of other criteria and hazardous air pollutants.	
Net benefits	−$58.7 and $340	−$8.01 and $46.4.

Notes: Values rounded to three significant figures. Monetized benefits were calculated using BPT estimates. The BPT estimates comprise several point estimates of mortality and morbidity. The two benefits estimates are separated by the word "and" to signify that they are two separate estimates and do not represent lower- and upper-bound estimates. Alternative calculation of monetized benefits reflects alternative assumptions regarding the monetization of emissions changes.

B. Paperwork Reduction Act (PRA)

The information collection activities in this proposed rule have been submitted for approval to the Office of Management and Budget (OMB) under the PRA. The Information Collection Request (ICR) document that the EPA prepared has been assigned EPA ICR number 2177.09. You can find a copy of the ICR in the docket for this rulemaking, and it is briefly summarized here.

• *Respondents/affected entities:* Owners and operators of new, modified, or reconstructed stationary combustion turbines.
• *Respondent's obligation to respond:* Mandatory.
• *Estimated number of respondents:* 5.
• *Frequency of response:* Semi-annual.
• *Total estimated burden:* 310 hours per year. Burden is defined at 5 CFR 1320.3(b).
• *Total estimated cost:* $36,000 per year, includes $0 annualized capital or operation & maintenance costs.

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.

Submit your comments on the Agency's need for this information, the accuracy of the provided burden estimates and any suggested methods for minimizing respondent burden to the EPA using the docket identified at the beginning of this rulemaking. The EPA will respond to any ICR-related comments in the final rule. You may also send your ICR-related comments to OMB's Office of Information and Regulatory Affairs (OIRA) using the interface at *www.reginfo.gov/public/do/PRAMain.* Find this particular information collection by selecting "Currently under Review—Open for Public Comments" or by using the search function. OMB must receive comments no later than January 13, 2025.

C. Regulatory Flexibility Act (RFA)

I certify that this proposed NSPS will not have a significant economic impact on a substantial number of small entities under the RFA. The small entities subject to the requirements of this proposed rule are private companies, investor-owned utilities, cooperatives, municipalities, and sub-divisions that would seek to build and operate stationary combustion turbines in the future. Based on an analysis of the existing combustion turbines constructed over the past five years and assuming that the percentage of small entities in that analysis is representative of the percentage of small entities who will own combustion turbines in the future, the EPA has estimated that one turbine constructed in each year from 2028–2032 may be owned by a small entity. Assuming that this entity will have sales that are an average of the existing small entities, the affected small entity is estimated to have annual compliance costs of 0.01 percent of its sales. Details of this analysis are presented in the Economic Impact Analysis for the New Source Performance Standards Review for Stationary Combustion Turbines.

D. Unfunded Mandates Reform Act (UMRA)

This proposed NSPS does not contain an unfunded mandate of $100 million (adjusted annually for inflation) or more (in 1995 dollars) as described in UMRA, 2 U.S.C. 1531–1538. The costs involved in this action are estimated not to exceed $183 million in 2023$ ($100 million in 1995$ adjusted for inflation using the GDP implicit price deflator) or more in any one year.

E. Executive Order 13132: Federalism

This action does not have federalism implications. It will 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.

Although the direct compliance costs may not be substantial, the EPA nonetheless elected to consult with representatives of State and local governments in the process of developing this action to permit them to have meaningful and timely input into their development. The EPA invited the following 10 national organizations representing State and local elected officials to a virtual meeting on August 15, 2024: (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. These 10 organizations representing elected State and local officials have been identified by the EPA as the "Big 10" organizations appropriate to contact for purpose of consultation with elected officials. Also, the EPA invited air and utility professional groups who may have State and local government members, including the Association of Air Pollution Control Agencies; National Association of Clean Air Agencies; American Public Power Association; Large Public Power Council; National Rural Electric Cooperative Association; National Association of Regulatory Utility Commissioners; and National Association of State Energy Officials to participate in the meeting. The purpose of the consultation was to provide general background on the rulemaking, answer questions, and solicit input from State and local governments. In the spirit of E.O. 13132, and consistent with EPA policy to promote communications between 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 proposed NSPS does not have Tribal implications as specified in Executive Order 13175. The proposed rule will not have substantial direct effects on Tribal governments, on the relationship between the Federal government and Indian tribes, or on the distribution of power and responsibilities between the Federal government and Indian tribes. The EPA is not aware of any stationary combustion turbine owned or operated by Indian Tribal governments. However, if there are any, the effect of the proposed rule on communities of Tribal governments would not be unique or disproportionate to the effect on other communities. Thus, Executive Order 13175 does not apply to this proposed rule.

Because the EPA is aware of Tribal interest in these proposed rules and consistent with the EPA Policy on Consultation and Coordination with Indian Tribes, the EPA offered government-to-government consultation with Tribes in April 2024.

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

Executive Order 13045 directs Federal agencies to include an evaluation of the health and safety effects of the planned regulation on children in Federal health and safety standards and explain why the regulation is preferable to potentially effective and reasonably feasible alternatives. While the environmental health or safety risks addressed by this action present a disproportionate risk to children because children typically have the highest ozone exposures since they are active outside during the summer when ozone levels are the highest and children are more at risk than adults from the effects of ozone exposure because their respiratory systems are still developing, this action is not subject to Executive Order 13045 because it is not a significant regulatory action under section 3(f)(1) of Executive Order 12866, as amended by Executive Order 14094.

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

This proposed NSPS is not a ''significant energy action'' because it is not likely to have a significant adverse effect on the supply, distribution or use of energy. The EPA does not expect a significant change in retail electricity prices on average across the contiguous U.S., coal-fired electricity generation, natural gas-fired electricity generation, or utility power sector delivered natural gas prices.

I. National Technology Transfer and Advancement Act (NTTAA) and 1 CFR Part 51

This proposed action involves technical standards. Therefore, the EPA conducted searches for the Review of New Source Performance Standards for Stationary Combustion Turbines through the Enhanced National Standards Systems Network (NSSN) Database managed by the American National Standards Institute (ANSI). Searches were conducted for EPA Methods 1, 2, 3A, 6, 6C, 7E, 8, 19, and 20 of 40 CFR part 60, appendix A. No applicable voluntary consensus standards were identified for EPA Methods 7E, 8, and 19. All potential standards were reviewed to determine the practicality of the voluntary consensus standards (VCS) for this rulemaking. One VCS were identified as an acceptable alternative to EPA test methods for the purpose of this proposed rule. The voluntary consensus standard ANSI/ASME PTC 19–10–1981 Part 10 (2010), ''Flue and Exhaust Gas Analyses'' is an acceptable alternative to EPA Methods 6 and 7 manual portion only and not the instrumental portion.

The search identified 13 VCS that were potentially applicable for this proposed rule in lieu of EPA reference methods. However, these have been determined to not be practical due to lack of equivalency, documentation, validation of data and other important technical and policy considerations. In this rule, the EPA is proposing to include in a final EPA rule regulatory text for 40 CFR part 60, subpart KKKKa that includes incorporation by reference. In accordance with requirements of 1 CFR 51.5, the EPA is proposing to incorporate by reference VCS ANSI/ASME PTC 19.10–1981 Part 10, ''Flue and Exhaust Gas Analyses,'' a method for quantitatively determining the gaseous constituents of exhausts resulting from stationary combustion and includes a description of the apparatus, and calculations used which are used in conjunction with Performance Test Codes to determine quantitatively, as an acceptable alternative to EPA Methods 6 and 7 of appendix A to 40 CFR part 60 for the manual procedures only and not the instrumental procedures. The ANSI/ASME PTC 19.10–1981 Part 10 method incorporates both manual and instrumental methodologies for the determination of oxygen content. The manual method segment of the oxygen determination is performed through the absorption of oxygen. This method is available at the American National Standards Institute (ANSI) and the American Society of Mechanical Engineers (ASME). Contact ANSI at 1899 L Street NW, 11th floor, Washington, DC 20036; phone: (202) 293–8020; website: *https://www.ansi.org.* Contact ASME at Two Park Avenue, New York, NY 10016–5990; phone (800) 843–2763; website: *https://www.asme.org.* The incorporation by reference of certain other material that will be included in the final rule was approved by the Director of the Federal Register as of July 3, 2017.

For additional information, please see the August 27, 2024, memorandum titled, *Voluntary Consensus Standard Results for Review of New Source Performance Standards for Stationary Combustion Turbines,* available in the rulemaking docket.

The EPA welcomes comments on this aspect of the proposed rulemaking and, specifically, invites the public to identify potentially applicable voluntary consensus standard (VCS) and to explain why such standards should be used in this regulations.

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations and Executive Order 14096: Revitalizing Our Nation's Commitment to Environmental Justice for All

For new sources constructed after the date of publication of this proposed action under CAA section 111(b), the EPA believes that it is not practicable to assess whether the human health or environmental conditions that exist prior to this action result in disproportionate and adverse effects on communities with environmental justice concerns because the location and number of new sources is unknown.

The determination that an impact is disproportionate is a policy judgment, as discussed in the *EJ Technical Guidance.* While the locations of newly constructed sources that will become subject to the proposed action are not known, the EPA examined the potential for any EJ issues that might be associated with the proposed NSPS by performing a proximity demographic analysis for 130 existing facilities that are currently subject to NSPS subpart KKKK. These represent facilities that might modify or reconstruct in the future and become subject to the proposed KKKKa requirements. This proximity demographic analysis is summarized in section IV.F of this preamble.

Michael S. Regan,

Administrator.

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