ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[EPA–HQ–OAR–2013–0602; FRL–9911–86–OAR]

RIN 2060–AR33

Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: In this action, the Environmental Protection Agency (EPA) is proposing emission guidelines for states to follow in developing plans to address greenhouse gas emissions from existing fossil fuel-fired electric generating units. Specifically, the EPA is proposing state-specific rate-based goals for carbon dioxide emissions from the power sector, as well as guidelines for states to follow in developing plans to achieve the state-specific goals. This rule, as proposed, would continue progress already underway to reduce carbon dioxide emissions from existing fossil fuel-fired power plants in the United States.

DATES: *Comments on the proposed rule.* Comments must be received on or before October 16, 2014. *Comments on the information collection request.* Under the Paperwork Reduction Act (PRA), since the Office of Management and Budget (OMB) is required to make a decision concerning the information collection request between 30 and 60 days after June 18, 2014, a comment to the OMB is best assured of having its full effect if the OMB receives it by July 18, 2014.

Public Hearing. Four public hearings will be convened. On July 29, 2014, one public hearing will be held in Atlanta, Georgia, at the Sam Nunn Atlanta Federal Center Main Tower Bridge Conference Area, Conference Room B, 61 Forsyth Street SW., Atlanta, GA 30303, and one will be held in Denver, Colorado, at the EPA's Region 8 Building, 1595 Wynkoop Street, Denver, Colorado 80202. On July 30, 2014, a public hearing will be held in Washington, DC, at the William Jefferson Clinton East Building, Room 1152, 1201 Constitution Avenue NW., Washington, DC 20004. On July 31, 2014, a public hearing will be held in Pittsburgh, Pennsylvania at the William S. Moorhead Federal Building, Room 1310, 1000 Liberty Avenue, Pittsburgh, Pennsylvania 15222. The hearings in Pittsburgh, Pennsylvania, Atlanta, Georgia, and Washington, DC, will convene at 9:00 a.m. and end at 8:00 p.m. (Eastern Standard Time). The hearing in Denver, Colorado, will convene at 9:00 a.m. and end at 8:00 p.m. (Mountain Daylight Time). For all hearings there will be a lunch break from 12:00 p.m. to 1:00 p.m. and a dinner break from 5:00 p.m. to 6:00 p.m. Please contact Ms. Pamela Garrett at 919–541–7966 or at *garrett.pamela@epa.gov* to register to speak at one of the hearings. The last day to pre-register in advance to speak at the hearings will be Friday, July 25, 2014. Additionally, requests to speak will be taken the day of the hearings at the hearing registration desk, although preferences on speaking times may not be able to be fulfilled. If you require the service of a translator or special accommodations such as audio description, please let us know at the time of registration.

The hearings will provide interested parties the opportunity to present data, views or arguments concerning the proposed action. The EPA will make every effort to accommodate all speakers who arrive and register. Because these hearings are being held at U.S. government facilities, individuals planning to attend the hearing should be prepared to show valid picture identification to the security staff in order to gain access to the meeting room. Please note that the REAL ID Act, passed by Congress in 2005, established new requirements for entering federal facilities. These requirements will take effect July 21, 2014. If your driver's license is issued by Alaska, American Samoa, Arizona, Kentucky, Louisiana, Maine, Massachusetts, Minnesota, Montana, New York, Oklahoma, or the state of Washington, you must present an additional form of identification to enter the federal buildings where the public hearings will be held. Acceptable alternative forms of identification include: Federal employee badges, passports, enhanced driver's licenses and military identification cards. We will list any additional acceptable forms of identification at: *http://www2.epa.gov/cleanpowerplan/*. In addition, you will need to obtain a property pass for any personal belongings you bring with you. Upon leaving the building, you will be required to return this property pass to the security desk. No large signs will be allowed in the building, cameras may only be used outside of the building and demonstrations will not be allowed on federal property for security reasons.

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 comments and supporting information presented at the public hearing. Commenters should notify Ms. Garrett if they will need specific equipment, or if there are other special needs related to providing comments at the hearings. Verbatim transcripts of the hearings and written statements will be included in the docket for the rulemaking. 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 hearings to run either ahead of schedule or behind schedule. Additionally, more information regarding the hearings will be available at: *http://www2.epa.gov/cleanpowerplan/.*

ADDRESSES: *Comments.* Submit your comments, identified by Docket ID No. EPA–HQ–OAR–2013–0602, by one of the following methods:

Federal eRulemaking portal: http://www.regulations.gov. Follow the online instructions for submitting comments.

Email: A-and-R-Docket@epa.gov. Include docket ID No. EPA–HQ–OAR–2013–0602 in the subject line of the message.

Facsimile: (202) 566–9744. Include docket ID No. EPA–HQ–OAR–2013–0602 on the cover page.

Mail: Environmental Protection Agency, EPA Docket Center (EPA/DC), Mail code 28221T, Attn: Docket ID No. EPA–HQ–OAR–2013–0602, 1200 Pennsylvania Ave. NW., Washington, DC 20460. In addition, please mail a copy of your comments on the information collection provisions to the Office of Information and Regulatory Affairs, OMB, Attn: Desk Officer for the EPA, 725 17th St. NW., Washington, DC 20503.

Hand/Courier Delivery: EPA Docket Center, Room 3334, EPA WJC West Building, 1301 Constitution Ave. NW., Washington, DC 20004, Attn: Docket ID No. EPA–HQ–OAR–2013–0602. Such deliveries are accepted only during the Docket Center's normal hours of operation (8:30 a.m. to 4:30 p.m., Monday through Friday, excluding federal holidays), and special arrangements should be made for deliveries of boxed information.

Instructions: All submissions must include the agency name and docket ID number (EPA–HQ–OAR–2013–0602). The EPA's policy is to include all comments received without change, including any personal information provided, in the public docket, available online at *http://www.regulations.gov*, unless the comment includes information claimed to be Confidential

Business Information (CBI) or other information whose disclosure is restricted by statute. Do not submit information that you consider to be CBI or otherwise protected through *http://www.regulations.gov* or email. Send or deliver information identified as CBI only to the following address: Mr. Roberto Morales, OAQPS Document Control Officer (C404–02), Office of Air Quality Planning and Standards, U.S. EPA, Research Triangle Park, North Carolina 27711, Attention Docket ID No. EPA–HQ–OAR–2013–0602. Clearly mark the part or all of the information that you claim to be CBI. For CBI information on a disk or CD–ROM that you mail to the EPA, mark the outside of the disk or CD–ROM as CBI and then identify electronically within the disk or CD–ROM the specific information you claim as CBI. In addition to one complete version of the comment that includes information claimed as CBI, you must submit a copy of the comment that does not contain the information claimed as CBI for inclusion in the public docket. Information so marked will not be disclosed except in accordance with procedures set forth in 40 CFR Part 2.

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

The *www.regulations.gov* Web site is an ''anonymous access'' system, which means the EPA will not know your identity or contact information unless you provide it in the body of your comment. If you send an email comment directly to the EPA without going through *http://www.regulations.gov*, your email address will be automatically captured and included as part of the comment that is placed in the public docket and made available on the Internet. If you submit an electronic comment, the EPA recommends that you include your name and other contact information in the body of your comment and with any disk or CD–ROM you submit. If the EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, the EPA may not be able to consider your comment. Electronic files should avoid the use of special characters, any form of encryption and be free of any defects or viruses.

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

In addition to being available in the docket, an electronic copy of this proposed rule will be available on the Worldwide Web (WWW). Following signature, a copy of this proposed rule will be posted at the following address: *http://www2.epa.gov/cleanpowerplan/*.

FOR FURTHER INFORMATION CONTACT: Ms. Amy Vasu, Sector Policies and Programs Division (D205–01), U.S. EPA, Research Triangle Park, NC 27711; telephone number (919) 541–0107, facsimile number (919) 541–4991; email address: *vasu.amy@epa.gov* or Ms. Marguerite McLamb, Sector Policies and Programs Division (D205–01), U.S. EPA, Research Triangle Park, NC 27711; telephone number (919) 541–7858, facsimile number (919) 541–4991; email address: *mclamb.marguerite@epa.gov*.

SUPPLEMENTARY INFORMATION:

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

ACEEE American Council for an Energy Efficient Economy
AEO Annual Energy Outlook
AFL–CIO American Federation of Labor and Congress of Industrial Organizations
ASTM American Society for Testing of Materials
BSER Best System of Emission Reduction
Btu/kWh British Thermal Units per Kilowatt-hour
CAA Clean Air Act
CBI Confidential Business Information
CCS Carbon Capture and Storage (or Sequestration)
CEMS Continuous Emissions Monitoring System
CHP Combined Heat and Power
CO_2 Carbon Dioxide
DOE Department of Energy
ECMPS Emissions Collection and Monitoring Plan System
EERS Energy Efficiency Resource Standard
EGU Electric Generating Unit
EIA Energy Information Administration
EM&V Evaluation, Measurement and Verification
EO Executive Order
EPA Environmental Protection Agency
FR **Federal Register**
GHG Greenhouse Gas
GW Gigawatt
HAP Hazardous Air Pollutant
HRSG Heat Recovery Steam Generator
IGCC Integrated Gasification Combined Cycle
IPCC Intergovernmental Panel on Climate Change
IPM Integrated Planning Model
IRP Integrated Resource Plan
ISO Independent System Operator
kW Kilowatt
kWh Kilowatt-hour
lb CO_2/MWh Pounds of CO_2 per Megawatt-hour
LBNL Lawrence Berkeley National Laboratory
MMBtu Million British Thermal Units
MW Megawatt
MWh Megawatt-hour
NAAQS National Ambient Air Quality Standards
NAICS North American Industry Classification System Commissioners
NAS National Academy of Sciences
NGCC Natural Gas Combined Cycle
NO_X Nitrogen Oxides
NRC National Research Council
NSPS New Source Performance Standard
NSR New Source Review
NTTAA National Technology Transfer and Advancement Act
NYSERDA New York State Energy Research and Development Authority
OMB Office of Management and Budget
PM Particulate Matter
$PM_{2.5}$ Fine Particulate Matter
PRA Paperwork Reduction Act
PSB Public Service Board
PUC Public Utilities Commission
REC Renewable Energy Credit
RES Renewable Energy Standard
RFA Regulatory Flexibility Act
RGGI Regional Greenhouse Gas Initiative
RIA Regulatory Impact Analysis
RPS Renewable Portfolio Standard
RTO Regional Transmission Operator
SBA Small Business Administration
SBC System Benefits Charge
SCC Social Cost of Carbon
SIP State Implementation Plan
SO_2 Sulfur Dioxide
Tg Teragram (one trillion (10^{12}) grams)
TSD Technical Support Document
TTN Technology Transfer Network
UMRA Unfunded Mandates Reform Act of 1995
UNFCCC United Nations Framework Convention on Climate Change
USGCRP U.S. Global Change Research Program
VCS Voluntary Consensus Standard

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

I. General Information

A. Executive Summary

1. Purpose of the Regulatory Action

Under the authority of Clean Air Act (CAA) section 111(d), the EPA is proposing emission guidelines for states to follow in developing plans to address greenhouse gas (GHG) emissions from existing fossil fuel-fired electric generating units (EGUs). In this summary, we outline the proposal; discuss its purpose; summarize its major provisions, including the EPA's approach to determining goals; describe the broad range of options available to states, including flexibility in timing requirements both for plan submission and compliance deadlines under those plans; and briefly describe the estimated CO_2 emission reductions, costs and benefits expected to result from full implementation of the proposal.

This rule, as proposed, would continue progress already underway to lower the carbon intensity of power generation in the United States (U.S.). Lower carbon intensity means fewer emissions of CO_2, a potent greenhouse gas that contributes to climate change. This proposal is a significant step forward in the EPA and states partnering to reduce GHG emissions in the U.S. The proposal incorporates critical elements that reflect the information and views shared during the unprecedented effort that the EPA has undertaken, beginning in the summer of 2013, to interact directly with, and solicit input from, a wide range of states and stakeholders. This effort encompassed several hundred meetings across the country with state environmental and energy officials, public utility commissioners, system operators, utilities and public interest advocates, as well as members of the public. Many participants submitted written material and data to the EPA as well.

Nationwide, by 2030, this rule would achieve CO_2 emission reductions from the power sector of approximately 30 percent from CO_2 emission levels in 2005. This goal is achievable because innovations in the production, distribution and use of electricity are already making the power sector more efficient and sustainable while maintaining an affordable, reliable and diverse energy mix. This proposed rule would reinforce and continue this progress. The EPA projects that, in 2030, the significant reductions in the harmful carbon pollution and in other air pollution, to which this rule would lead, would result in net climate and health benefits of $48 billion to $82 billion. At the same time, coal and natural gas would remain the two leading sources of electricity generation in the U.S., with each providing more than 30 percent of the projected generation.

Based on evidence from programs already being implemented by many states as well as input received from stakeholders, the agency recognizes that the most cost-effective system of emission reduction for GHG emissions from the power sector under CAA section 111(d) entails not only improving the efficiency of fossil fuel-fired EGUs, but also addressing their utilization by taking advantage of opportunities for lower-emitting generation and reduced electricity demand across the electricity system's interconnecting network or grid.

The proposed guidelines are based on and would reinforce the actions already being taken by states and utilities to upgrade aging electricity infrastructure with 21st century technologies. The guidelines would ensure that these trends continue in ways that are consistent with the long-term planning and investment processes already used in this sector, to meet both region- and state-specific needs. The proposal provides flexibility for states to build upon their progress, and the progress of cities and towns, in addressing GHGs. It also allows states to pursue policies to reduce carbon pollution that: (1)

Continue to rely on a diverse set of energy resources, (2) ensure electric system reliability, (3) provide affordable electricity, (4) recognize investments that states and power companies are already making, and (5) can be tailored to meet the specific energy, environmental and economic needs and goals of each state. Thus, the proposed guidelines would achieve meaningful CO_2 emission reduction while maintaining the reliability and affordability of electricity in the U.S.

a. Proposal Elements

The proposal has two main elements: (1) State-specific emission rate-based CO_2 goals and (2) guidelines for the development, submission and implementation of state plans. To set the state-specific CO_2 goals, the EPA analyzed the practical and affordable strategies that states and utilities are already using to lower carbon pollution from the power sector. These strategies include improvements in efficiency at carbon-intensive power plants, programs that enhance the dispatch priority of, and spur private investments in, low emitting and renewable power sources, as well as programs that help homes and businesses use electricity more efficiently. In addition, in calculating each state's CO_2 goal, the EPA took into consideration the state's fuel mix, its electricity market and numerous other factors. Thus, each state's goal reflects its unique conditions.

While this proposal lays out state-specific CO_2 goals that each state is required to meet, it does not prescribe how a state should meet its goal. CAA section 111(d) creates a partnership between the EPA and the states under which the EPA sets these goals and the states take the lead on meeting them by creating plans that are consistent with the EPA guidelines. Each state will have the flexibility to design a program to meet its goal in a manner that reflects its particular circumstances and energy and environmental policy objectives. Each state can do so alone or can collaborate with other states on multi-state plans that may provide additional opportunities for cost savings and flexibility.

To facilitate the state planning process, this proposal lays out guidelines for the development and implementation of state plans. The proposal describes the components of a state plan, the latitude states have in developing compliance strategies, the flexibility they have in the timing for submittal of their plans and the flexibility they have in determining the schedule by which their sources must achieve the required CO_2 reductions. The EPA recognizes that each state has differing policy considerations—including varying emission reduction opportunities and existing state programs and measures—and that the characteristics of the electricity system in each state (e.g., utility regulatory structure, generation mix and electricity demand) also differ. Therefore, the proposed guidelines provide states with options for meeting the state-specific goals established by the EPA in a manner that accommodates a diverse range of state approaches. This proposal also gives states considerable flexibility with respect to the timeframes for plan development and implementation, providing up to two or three years for submission of final plans and providing up to fifteen years for full implementation of all emission reduction measures, after the proposal is finalized.

Addressing a concern raised by both utilities and states, the EPA is proposing that states could choose approaches in their compliance plans under which full responsibility for actions achieving reductions is not placed entirely upon emitting EGUs; instead, state plans could include measures and policies (e.g., demand-side energy efficiency programs and renewable portfolio standards) for which the state itself is responsible. Of course, individual states would also have the option of structuring programs (e.g., allowance-trading programs) under which full responsibility rests on the affected EGUs.

The EPA believes that, using the flexibilities inherent in CAA section 111(d), this proposal would result in significant reductions of GHG emissions that cause harmful climate change, while providing states with ample opportunity to design plans that use innovative, cost-effective strategies that take advantage of investments already being made in programs and measures that lower the carbon intensity of the power sector and reduce GHG emissions.

b. Policy Context and Industry Conditions

This proposal is an important step toward achieving the GHG emission reductions needed to address the serious threat of climate change. GHG pollution threatens the American public by leading to potentially rapid, damaging and long-lasting changes in our climate that can have a range of severe negative effects on human health and the environment. CO_2 is the primary GHG pollutant, accounting for nearly three-quarters of global GHG emissions [1] and 82 percent of U.S. GHG emissions.[2] The May 2014 report of the National Climate Assessment [3] concluded that climate change impacts are already manifesting themselves and imposing losses and costs. The report documents increases in extreme weather and climate events in recent decades, damage and disruption to infrastructure and agriculture, and projects continued increases in impacts across a wide range of communities, sectors, and ecosystems.

The President's Climate Action Plan,[4] issued in June 2013, recognizes that climate change has far-reaching harmful consequences and real economic costs. The Climate Action Plan details a broad array of actions to reduce GHG emissions that contribute to climate change and affect public health and the environment. One of the plan's goals is to reduce CO_2 emissions from power plants. This is because fossil fuel-fired EGUs are, by far, the largest emitters of GHGs, primarily in the form of CO_2, among stationary sources in the U.S. To accomplish this goal, President Obama issued a Presidential Memorandum [5] that recognized the importance of significant and prompt action. The Memorandum directed the EPA to complete carbon pollution standards, regulations or guidelines, as appropriate, for modified, reconstructed and existing power plants by June 1, 2015, and in doing so to build on state leadership in moving toward a cleaner power sector.

The way that power is produced, distributed and used is already changing due to advancements in innovative power sector technologies and in the availability and cost of low carbon fuel, renewable energy and energy efficient demand-side technologies, as well as economic conditions. In addition, the average age of the coal-fired generating fleet is increasing. In 2025, the average age of the coal-fired generating fleet is

[1] Intergovernmental Panel on Climate Change (IPCC) report, ''Contribution of Working Group I to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change,'' 2007. Available at *http://epa.gov/climatechange/ghgemissions/global.html.*

[2] Table ES–2 ''Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2012'', Report EPA 430–R–14–003, United States Environmental Protection Agency, April 15, 2014.

[3] U.S. Global Change Research Program, Climate Change Impacts in the United States: The Third National Climate Assessment, May 2014. Available at *http://nca2014.globalchange.gov/.*

[4] The President's Climate Action Plan, June 2013. *http://www.whitehouse.gov/sites/default/files/image/president27sclimateactionplan.pdf.*

[5] Presidential Memorandum—Power Sector Carbon Pollution Standards, June 25, 2013. *http://www.whitehouse.gov/the-press-office/2013/06/25/presidential-memorandum-power-sector-carbon-pollution-standards.*

projected to be 49 years old, and 20 percent of units would be more than 60 years old if they remained in operation at that time. Therefore, even in the absence of additional environmental regulation, states and utilities can be expected to be, and already are, making plans to address the changes necessitated by the aging of current assets and infrastructure. With change inevitably underway between now and 2030, a CAA section 111(d) rulemaking for CO_2 emissions is timely and can inform current and ongoing decision making by states and utilities, as well as private sector business and technology investments. As states develop their plans, they will make key decisions that will stimulate private sector investment and innovation associated with reducing GHG emissions. We expect that many states will consider the opportunities offered for their respective economies as a result of this investment.

The proposed guidelines are designed to build on and reinforce progress by states, cities and towns, and companies on a growing variety of sustainable strategies to reduce power sector CO_2 emissions. At the same time, the EPA believes that this proposal provides flexibility for states to develop plans that align with their unique circumstances, as well as their other environmental policy, energy and economic goals. All states will have the opportunity to shape their plans as they believe appropriate for meeting the proposed CO_2 goals. This includes states with long-established reliance on coal-fired generation, as well as states with a commitment to promoting renewable energy (including through sustainable forestry initiatives). It also includes states that are already participating in or implementing CO_2 reduction programs, such as the Regional Greenhouse Gas Initiative (RGGI), California's ''Global Warming Solutions Act'' and Colorado's ''Clean Air, Clean Jobs Act''.

States would be able to rely on and extend programs they may already have created to address the power sector. Those states committed to Integrated Resource Planning (IRP) would be able to establish their CO_2 reduction plans within that framework, while states with a more deregulated power sector system could develop CO_2 reduction plans within that specific framework. Each state, including states without an existing program, would have the opportunity to take advantage of a wide variety of strategies for reducing CO_2 emissions from affected EGUs. The EPA and other federal entities, including the U.S. Department of Energy (DOE), the Federal Energy Regulatory Commission (FERC) and the U.S. Department of Agriculture, among others, are committed to sharing expertise with interested states as they develop and implement their plans.

States would be able to address the economic interests of their utilities and ratepayers by using the flexibilities in this proposed action to: (1) Reduce costs to consumers, minimize stranded assets, and spur private investments in renewable energy and energy efficiency technologies and businesses; and (2) if they choose, work with other states on multi-state approaches that reflect the regional structure of electricity operating systems that exists in most parts of the country and is critical to ensuring a reliable supply of affordable energy. The proposed rule gives states the flexibility to provide a broad range of compliance options that recognize that the power sector is made up of a diverse range of companies that own and operate fossil fuel-fired EGUs, including vertically integrated companies in regulated markets, independent power producers, rural cooperatives and municipally-owned utilities, all of which are likely to have different ranges of opportunities to reduce GHG emissions while facing different challenges in meeting these reductions.

Both existing state programs (such as RGGI, the California Global Warming Solutions Act program and the Colorado Clean Air, Clean Jobs Act program) and ideas suggested by stakeholders show that there are a number of different ways that states can design programs that achieve required reductions while working within existing market mechanisms used to dispatch power effectively in the short term and to ensure adequate capacity in the long term. These programs and programs for conventional pollutants, such as the Acid Rain Program under Title IV of the CAA, have demonstrated that compliance with environmental programs can be monetized such that it is factored into power sector economic decision making in ways that reduce the cost of controlling pollution, maintain electricity system reliability and work within the least cost dispatching principles that are key to operation of our electric power grid. The proposal would also allow states to work together with individual companies on potential specific challenges. These and other flexibilities are discussed further in Section VIII of the preamble.

a. CAA Section 111(d) Requirements

Under CAA section 111(d),[6] state plans must establish standards of performance that reflect the degree of emission limitation achievable through the application of the ''best system of emission reduction'' that, taking into account the cost of achieving such reduction and any non-air quality health and environmental impacts and energy requirements, the Administrator determines has been adequately demonstrated (BSER).[7] Consistent with CAA section 111(d), the EPA is proposing state-specific goals that reflect the EPA's calculation of the emission limitation that each state can achieve through the application of the BSER. This calculation reflects the degree of emission limitation that the state plan must achieve in order to implement the BSER that the EPA has determined has been adequately demonstrated and that, in turn, would be required to be, and via the calculation, has been, applied for the affected EGUs in each state. A CAA section 111(d) state plan will differ from a state implementation plan (SIP) for a criteria air pollutant national ambient air quality standard (NAAQS) in several respects, reflecting the significant differences between CAA sections 110 and 111. A CAA section 110 SIP must be designed to meet the NAAQS for a criteria air pollutant for a particular area—not for a source category—within a timeframe specified in the CAA. The NAAQS itself is based on the current body of scientific evidence and, by law, does not reflect consideration of cost. By contrast, a CAA section 111(d) state plan must be designed to achieve a specific level of emission performance that has been established for a particular source category within a timeframe determined by the Administrator and, to some extent, by each state. Moreover, the emission levels for the source category reflect a determination of the BSER, which incorporates consideration of cost, technical feasibility and other factors.

To determine the BSER for reducing CO_2 emissions at affected EGUs, the EPA considered numerous measures that are already being implemented and can be implemented more broadly to

[6] See also 40 CFR 60.22(b)(5).

[7] Under CAA section 111(a)(1) and (d), the EPA is authorized to determine the BSER and to calculate the amount of emission reduction achievable through applying the BSER. The state is authorized to identify the standard or standards of performance that reflects that amount of emission reduction. In addition, the state is required to include in its state plan the standards of performance and measures to implement and enforce those standards. The state must submit the plan to the EPA, and the EPA must approve the plan if the standards of performance and implementing and enforcing measures are satisfactory. This is discussed in more detail in Sections IV, VI, VII and VIII of this preamble, as well as in the Legal Memorandum.

improve emission rates and to reduce overall CO_2 emissions from fossil fuel-fired EGUs. Overall, the BSER proposed here is based on a range of measures that fall into four main categories, or ''building blocks,'' which comprise improved operations at EGUs, dispatching lower-emitting EGUs and zero-emitting energy sources, and end-use energy efficiency. All of these measures have been amply demonstrated via their current widespread use by utilities and states.

The proposed guidelines are structured so that states would not be required to use each and every one of the measures that the EPA determines constitute the BSER or to apply any one of those measures to the same extent that the EPA determines is achievable at reasonable cost. Instead, in developing its plan, each state will have the flexibility to select the measure or combination of measures it prefers in order to achieve its CO_2 emission reduction goal. Thus, a state could choose to achieve more reductions from one measure encompassed by the BSER and less from another, or it could choose to include measures that were not part of the EPA's BSER determination, as long as the state achieves the CO_2 reductions at affected EGUs necessary to meet the goal that the EPA has defined as representing the BSER.

As explained in further detail in Sections VI, VII and VIII of this preamble regarding the agency's determination of the BSER, the EPA is offering the opportunity via this proposal to comment on the proposed BSER, the proposed methodology for computing state goals based on application of the BSER, and the state-specific data used in the computations. Once the final goals have been promulgated, a state would no longer have an opportunity to request that the EPA adjust its CO_2 goal. The final state-specific CO_2 goals would reflect any adjustments as appropriate based on comments provided to the EPA to address any data errors in the analysis for the proposed goals. We expect that states will be able to meet the CO_2 goals because they will represent the application of the BSER for the states' affected sources.

This proposed rule sets forth the state goals that reflect the BSER and guidelines for states to use in developing their plans to reduce CO_2 from fossil fuel-fired EGUs. The preamble describes the proposed expectations for state plans and discusses options that the EPA has considered. It also explains the EPA's authority to define the BSER, as well as state goals, and each state's responsibility to develop and implement standards of performance that will achieve its CO_2 goal. Additional detail on various aspects of the proposal is included in several technical support documents (TSDs) and memoranda, which are available in the rulemaking docket.

The proposal was substantially informed by the extensive input from states and a wide range of stakeholders that the EPA sought and has received since the summer of 2013. The EPA invites further input through public comment on all aspects of this proposal.

2. Summary of the Proposal's Major Provisions

a. Approach

In developing this proposed rulemaking, the EPA is implementing statutory provisions that have been in place since Congress first enacted the CAA in 1970 and that have been implemented pursuant to regulations promulgated in 1975 and followed in subsequent CAA section 111(d) rulemakings. These provisions ensure that, in concert with the provisions of CAA sections 110 and 112, new and existing major stationary sources operate in ways that address their emissions of significant air pollutants that are harmful to public health and the environment. These requirements call on the EPA to develop emission guidelines, which reflect the EPA's determination of the BSER, for states to follow in formulating compliance plans to implement standards of performance to achieve emission reductions consistent with the BSER. In following these provisions, the EPA is proposing a BSER based on strategies currently being used by states and companies to reduce CO_2 emissions from EGUs.

The CAA, as interpreted by the courts, identifies several factors for the EPA to consider in a BSER determination. These include technical feasibility, costs, size of emission reductions and technology (e.g., whether the system promotes the implementation and further development of technology). In determining the BSER, the EPA considered the reductions achievable through measures that reduce CO_2 emissions from existing fossil fuel-fired EGUs either by (1) reducing the CO_2 emission rate at those units or (2) reducing the units' CO_2 emission total to the extent that generation can be shifted from higher-emitting fossil fuel-fired EGUs to lower- or zero-emitting options.

As the EPA has done in making BSER determinations in previous CAA section 111(d) rulemakings, the agency considered the types of strategies that states and owners and operators of EGUs are already employing to reduce the covered pollutant (in this case, CO_2) from affected sources (in this case, fossil fuel-fired EGUs).[8] Across the nation, many states, cities and towns, and owners and operators of EGUs have shown leadership in creating and implementing policies and programs that reduce CO_2 emissions from the power sector while achieving other economic, environmental and energy benefits. Some of these activities, such as market-based programs and GHG performance standards, directly require CO_2 emission reductions from EGUs. Others reduce CO_2 emissions by reducing utilization of fossil fuel-fired EGUs through, for example, renewable portfolio standards (RPS) and energy efficiency resource standards (EERS). For example, currently 10 states have market-based GHG emission programs, 38 states have renewable portfolio standards or goals, and utilities in 47 states run demand-side energy efficiency programs. Many individual companies also have significant voluntary CO_2 emission reduction programs.

Such strategies—and the proposed BSER determination—reflect the fact that, in almost all states, the production, distribution and use of electricity can be, and is, undertaken in ways that accommodate reductions in both pollution emission rates and total emissions. Specifically, electricity production, at least to some extent, takes place interchangeably between and among multiple generation facilities and different types of generation, a fact that Congress, the EPA and the states have long relied on in enacting or promulgating pollution reduction programs, such as Title IV of the CAA, the NO_X SIP Call, the Cross State Air Pollution Rule (CSAPR) and RGGI.

As a result, the agency, in quantifying state goals, assessed what combination of electricity production or energy demand reduction across generation facilities can offer a reasonable-cost, technically feasible approach to achieving CO_2 emission reductions. States, in turn, will be able to look broadly at opportunities across their

[8] The final emission guidelines for landfill gas emissions from municipal solid waste landfills, published on March 12, 1996 and amended on June 16, 1998 (61 FR 9905 and 63 FR 32743, respectively) are one example, as they allow either of two approaches for controlling landfill gas—by recovering the gas as a fuel, for sale, and removing from the premises, or by destroying the organic content of the gas on the premises using a control device. Recovering the gas as a fuel source was a practice already being used by some affected sources prior to promulgation of the rulemaking.

electricity system in devising plans to meet their goals. Importantly, states may rely on measures that they already have in place, including renewable energy standards and demand-side energy efficiency programs, and the proposal details how such existing state programs can be incorporated into state plans. States will also be able to participate in multi-state programs that already exist or may create new ones.

Thus, to determine the BSER for reducing CO_2 emissions at affected EGUs and to establish the numerical goals that reflect the BSER, the EPA considered numerous measures that can and are being implemented to improve emission rates and to reduce or limit mass CO_2 emissions from fossil fuel-fired EGUs. These measures encompass two basic approaches: (1) Reducing the carbon intensity of certain affected EGUs by improving the efficiency of their operations, and (2) addressing affected EGUs' mass emissions by varying their utilization levels. For purposes of expressing the BSER as an emission limitation, in this case in the form of state-level goals, we propose to base these two approaches on measures grouped into four main categories, or ''building blocks.'' These building blocks can also be used as a guide to states for constructing broad-based, cost-effective, long-term strategies to reduce CO_2 emissions. The EPA believes that the application of measures from each of the building blocks can achieve CO_2 emission reductions at fossil fuel-fired EGUs such that, when combined with measures from other building blocks, the measures represent the ''best system of emission reduction . . . adequately demonstrated'' for fossil fuel-fired EGUs. The building blocks are:

1. Reducing the carbon intensity of generation at individual affected EGUs through heat rate improvements.
2. Reducing emissions from the most carbon-intensive affected EGUs in the amount that results from substituting generation at those EGUs with generation from less carbon-intensive affected EGUs (including NGCC units under construction).
3. Reducing emissions from affected EGUs in the amount that results from substituting generation at those EGUs with expanded low- or zero-carbon generation.
4. Reducing emissions from affected EGUs in the amount that results from the use of demand-side energy efficiency that reduces the amount of generation required.

The four building blocks are described in detail in Sections VI of this preamble. As explained in that section, the EPA evaluated each of the building blocks individually against the BSER criteria and found that each of the building blocks independently merits consideration as part of the BSER. The EPA also evaluated combinations of the building blocks against the BSER criteria—in particular, a combination of all four building blocks and a combination of building blocks 1 and 2.

Based on that evaluation, the EPA proposes that the combination of all four building blocks is the BSER. The combination of all four blocks best represents the BSER because it achieves greater emission reductions at a lower cost, takes better advantage of the wide range of measures that states, cities, towns and utilities are already using to reduce CO_2 from EGUs and reflects the integrated nature of the electricity system and the diversity of electricity generation technology. Section VI of this preamble also explains how the EPA considered more aggressive application of measures in each block. This includes consideration of more extensive application of measures that the EPA determined do represent a component of the BSER (such as more extensive or accelerated application of demand-side measures), as well as consideration of options in some blocks that the EPA determined would not represent the BSER for existing sources (such as the inclusion of retrofit carbon capture and storage or sequestration (CCS) on existing EGUs).

As part of the BSER determination, the EPA considered the impacts that implementation of the emission reductions based on the combination of the blocks would have on the cost of electricity and electricity system reliability. As the preamble details, the EPA believes that, both with respect to the overall proposed BSER and with respect to the individual building blocks, the associated costs are reasonable. Importantly, the proposed BSER, expressed as a numeric goal for each state, provides states with the flexibility to determine how to achieve the reductions (i.e., greater reductions from one building block and less from another) and to adjust the timing in which reductions are achieved, in order to address key issues such as cost to consumers, electricity system reliability and the remaining useful life of existing generation assets.

In sum, the EPA proposes that the BSER for purposes of CAA section 111(d), as applied to existing fossil fuel-fired EGUs, is based on a combination of measures that reduce CO_2 emissions and CO_2 emission rates and encompass all four building blocks.[9] We are also soliciting comment on application of only the first two building blocks as the basis for the BSER, while noting that application of only the first two building blocks achieves fewer CO_2 reductions at a higher cost.

In determining the BSER, we have considered the ranges of reductions that can be achieved by application of each building block, and we have identified goals that we believe reflect a reasonable degree of application of each building block consistent with the BSER criteria. Relying on all four building blocks to characterize the combination of measures that reduce CO_2 emissions and CO_2 emission rates at affected EGUs as the basis for the BSER is consistent with strategies, actions and measures that companies and states are already undertaking to reduce GHG emissions and with current trends in the electric power sector, driven by efforts to reduce GHGs as well as by other factors, such as advancements in technology. Reliance on all four building blocks in this way also supports the goals of achieving significant and technically feasible reductions of CO_2 at a reasonable cost, while also promoting technology and approaches that are important for achieving further reductions. Finally, the EPA believes that the diverse range of measures encompassed in the four building blocks allows states and sources to take full advantage of the inherent flexibility of the current regionally interconnected and integrated electricity system so as to achieve the CO_2 goals while continuing to meet the demand for electricity services in a reliable and affordable manner.

The EPA recognizes that states differ in important ways, including in their mix of existing EGUs and in their policy priorities. Consequently, opportunities and preferences for reducing emissions, as reflected in each of the building blocks, vary across states. While the state-specific goals that the EPA is proposing in this rule are based on consistent application of a single goal-setting methodology across all states, the goals account for these key differences. The state-specific CO_2 goals derived from application of the methodology vary because, in setting the goals for a state, the EPA used data specific to each state's EGUs and certain

[9] The EPA notes that under the proposed BSER, some building blocks would apply to some, but not all, affected sources. Specifically, building block 1 would apply to affected coal-fired steam EGUs, building block 2 would apply to all affected steam EGUs (both coal-fired and oil/gas-fired), and building blocks 3 and 4 would apply to all affected EGUs.

other attributes of its electricity system (e.g., current mix of generation resources).

The proposed BSER and goal-setting methodology reflect information provided and priorities expressed during the EPA's recent, extensive public outreach process. The input we received ranged from the states' desires for flexibility and recognition of varying state circumstances to the success that states and companies have had in adopting a range of pollution—and demand-reduction strategies. The state-specific approach embodied in both CAA section 111(d) and this proposal recognizes that ultimately states are the most knowledgeable about their specific circumstances and are best positioned to evaluate and leverage existing and new generation capacity and programs to reduce CO_2 emissions.

To meet its goal, each state will be able to design programs that use the measures it selects, and these may include the combination of building blocks most relevant to its specific circumstances and policy preferences. States may also identify technologies or strategies that are not explicitly mentioned in any of the four building blocks and may use those technologies or strategies as part of their overall plans (e.g., market-based trading programs or construction of new natural combined cycle units or nuclear plants). Further, the EPA's approach allows multi-state compliance strategies.

The agency also recognizes the important functional relationship between the period of time over which measures are deployed and the stringency of emission limitations those measures can achieve in a practical and reasonable cost way. Because, for this proposal, the EPA is proposing a 10-year period over which to achieve the full required CO_2 reductions, a period that begins more than five years from the date of this proposal, a state could take advantage of this relationship in the design of its program by using relevant combinations of building blocks to achieve its state goal in a manner that provides for electricity system reliability, avoids the creation of stranded assets and has a reasonable cost.

b. State Goals and Flexibilities

In this action, the EPA is proposing state-specific rate-based goals that state plans must be designed to meet. These state-specific goals are based on an assessment of the amount of emissions that can be reduced at existing fossil fuel-fired EGUs through application of the BSER, as required under CAA section 111(d). The agency is proposing state-specific final goals that must be achieved by no later than the year 2030. The proposed final goals reflect the EPA's quantification of adjusted state-average emission rates from affected EGUs that could be achieved at reasonable cost by 2030 through implementation of the four building blocks described above.

The EPA recognizes that, with many measures, states can achieve emission reductions in the short-term, though the full effects of implementation of other measures, such as demand-side energy efficiency (EE) programs and the addition of renewable energy (RE) generating capacity, can take longer. Thus, the EPA is proposing interim goals that states must meet beginning in 2020. The proposed interim goals would apply over a 2020–2029 phase-in period. They reflect the level of reductions in CO_2 emissions and emission rates and the extent of the application of the building blocks that would be presumptively approvable in a state plan during the ramp-up to achieving the final goal.

The EPA is proposing to allow each state flexibility with regard to the form of the goal. A state could adopt the rate-based form of the goal established by the EPA or an equivalent mass-based form of the goal. A multi-state approach incorporating either a rate- or mass-based goal would also be approvable based upon a demonstration that the state's plan would achieve the equivalent in stringency, including compliance timing, to the state-specific rate-based goal set by the EPA.

We believe that this approach to establishing requirements for states in developing their plans responds both to the needs of an effectively implemented program and to the range of viewpoints expressed by stakeholders regarding the simultaneous need for both flexibility and clear guidance on what would constitute an approvable state plan. We likewise believe that this approach represents a reasonable balance between two competing objectives grounded in CAA section 111(d)—a need for rigor and consistency in calculating emission reductions reflecting the BSER and a need to provide the states with flexibility in establishing and implementing the standards of performance that reflect those emission reductions. The importance of this balance is heightened by the fact that the operations of the electricity system itself rely on the flexibility made available and achieved through dispatching between and among multiple interconnected EGUs, demand management and end-use energy efficiency. We view the proposed goals as providing rigor where required by the statute with respect to the amount of emission reductions, while providing states with flexibility where permitted by the statute, particularly with respect to the range of measures that a state could include in its plan. This approach recognizes that state plans for emission reductions can, and must, be consistent with a vibrant and growing economy and supply of reliable, affordable electricity to support that economy. It further reflects the growing trend, as exemplified by many state and local clean energy policies and programs, to shift energy production away from carbon-intensive fuels to a modern, more sustainable system that puts greater reliance on renewable energy, energy efficiency and other low-carbon energy options.

c. State Plans

i. Plan Approach

Each state will determine, and include in its plan, emission performance levels for its affected EGUs that are equivalent to the state-specific CO_2 goal in the emission guidelines, as well as the measures needed to achieve those levels and the overall goal. As part of determining these levels, the state will decide whether it will adopt the rate-based form of the goal established by the EPA or translate the rate-based goal to a mass-based goal. The state must then establish a standard, or set of standards, of performance, as well as implementing and enforcing measures, to achieve the emission performance level specified in the state plan. The state may choose the measures it will include in its plan to achieve its goal. The state may use the same set of measures as in the EPA's approach to setting the goals, or the state may use other or additional measures to achieve the required CO_2 reductions.

A state plan must include enforceable CO_2 emission limits that apply to affected EGUs. In doing so, a state plan may take a portfolio approach, which could include enforceable CO_2 emission limits that apply to affected EGUs as well as other enforceable measures, such as RE and demand-side EE measures, that avoid EGU CO_2 emissions and are implemented by the state or by another entity. The plan must also include a process for reporting on plan implementation, progress toward achieving CO_2 goals, and implementation of corrective actions, if necessary. No less frequently than every two rolling calendar years, beginning January 1, 2022, the state will be required to compare emission performance achieved by affected EGUs in the state with the emissions performance projected in the state plan, and report that to the EPA.

In this action, the EPA is also proposing guidelines for states to follow in developing their plans. These guidelines include approvability criteria, requirements for state plan components, the process and timing for state plan submittal and the process and timing for demonstrating achievement of the CO_2 emission performance level in the state plan. The proposed guidelines provide states with options for meeting the state-specific goals established by the EPA in a flexible manner that accommodates a diverse range of state approaches. The plan guidelines provide the states with the ability to achieve the full reductions over a multi-year period, through a variety of reduction strategies, using state-specific or multi-state approaches that can be achieved on either a rate or mass basis. They also address several key policy considerations that states can be expected to contemplate in developing their plans.

With respect to the structure of the state plans, the EPA, in its extensive outreach efforts, heard from a wide range of stakeholders that the EPA should authorize state plans to include a portfolio of actions that encompass a diverse set of programs and measures that achieve either a rate-based or mass-based emission performance level for affected EGUs but that do not place legal responsibility for achieving the entire amount of the emission performance level on the affected EGUs. In view of this strong sentiment from stakeholders, the EPA is proposing that state plans that take this portfolio approach would be approvable, provided that they meet other key requirements such as achieving the required emission reductions over the appropriate timeframes. Plans that do directly assure that affected EGUs achieve all of the required emission reductions (such as the mass-based programs being implemented in California and the RGGI states) would also be approvable provided that they meet other key requirements, such as achieving the required emission reductions over the appropriate timeframes.

ii. State Plan Components

The EPA is proposing to evaluate and approve state plans based on four general criteria: (1) Enforceable measures that reduce EGU CO_2 emissions; (2) projected achievement of emission performance equivalent to the goals established by the EPA, on a timeline equivalent to that in the emission guidelines; (3) quantifiable and verifiable emission reductions; and (4) a process for reporting on plan implementation, progress toward achieving CO_2 goals, and implementation of corrective actions, if necessary. In addition, each state plan must follow the EPA framework regulations at 40 CFR 60.23. The proposed components of states plans are:

- Identification of affected entities
- Description of plan approach and geographic scope
- Identification of state emission performance level
- Demonstration that plan is projected to achieve emission performance level
- Identification of emission standards
- Demonstration that each emission standard is quantifiable, non-duplicative, permanent, verifiable, and enforceable
- Identification of monitoring, reporting, and recordkeeping requirements
- Description of state reporting
- Identification of milestones
- Identification of backstop measures
- Certification of hearing on state plan
- Supporting material

iii. Process for State Plan Submittal and Review

Recognizing the urgent need for actions to reduce GHG emissions, and in accordance with the Presidential Memorandum,[10] the EPA expects to finalize this rulemaking by June 1, 2015. The Presidential Memorandum also calls for a deadline of June 30, 2016, for states to submit their state plans. The EPA is proposing that each state must submit a plan to the EPA by June 30, 2016. However, the EPA recognizes that some states may need more than one year to complete all of the actions needed for their final state plans, including technical work, state legislative and rulemaking activities, coordination with third parties, and coordination among states involved in multi-state plans. Therefore, the EPA is proposing an optional two-phased submittal process for state plans. Each state would be required to submit a plan by June 30, 2016, that contains certain required components. If a state needs additional time to submit a complete plan, then the state must submit an initial plan by June 30, 2016 that documents the reasons the state needs more time and includes commitments to concrete steps that will ensure that the state will submit a complete plan by June 30, 2017 or 2018, as appropriate. To be approvable, the initial plan must include specific components, including a description of the plan approach, initial quantification of the level of emission performance that will be achieved in the plan, a commitment to maintain existing measures that limit CO_2 emissions, an explanation of the path to completion, and a summary of the state's response to any significant public comment on the approvability of the initial plan, as described in Section VIII.E of this preamble.

If the initial plan includes those components and if the EPA does not notify the state that the initial plan does not contain the required components, the extension of time to submit a complete plan will be deemed granted and a state would have until June 30, 2017, to submit a complete plan if the geographic scope of the plan is limited to that state. If the state develops a plan that includes a multi-state approach, it would have until June 30, 2018 to submit a complete plan. Further, the EPA is proposing that states participating in a multi-state plan may submit a single joint plan on behalf of all of the participating states.

Following submission of final plans, the EPA will review plan submittals for approvability. Given the diverse approaches states may take to meet the emission performance goals in the emission guidelines, the EPA is proposing to extend the period for EPA review and approval or disapproval of plans from the four-month period provided in the EPA framework regulations to a twelve-month period.

iv. Timing of Compliance

As states, industry groups and other stakeholders have made clear, the EPA recognizes that the measures states have been and will be taking to reduce CO_2 emissions from existing EGUs can take time to implement. Thus, we are proposing that, while states must begin to make reductions by 2020, full compliance with the CO_2 emission performance level in the state plan must be achieved by no later than 2030. Under this proposed option, a state would need to meet an interim CO_2 emission performance level on average over the 10-year period from 2020–2029, as well as achieve its final CO_2 emission performance level by 2030 and maintain that level subsequently. This proposed option is based on the application of a range of measures from all four building blocks, and the agency believes that this approach for compliance timing is reasonable and appropriate and would best support the optimization of overall

[10] Presidential Memorandum—Power Sector Carbon Pollution Standards, June 25, 2013. *http://www.whitehouse.gov/the-press-office/2013/06/25/presidential-memorandum-power-sector-carbon-pollution-standards.*

CO_2 reductions. The agency is also requesting comment on an alternative option, a 5-year period for compliance, in combination with a less stringent set of CO_2 emission performance levels. These options are fully described in Section VIII of this preamble, and the state goals associated with the alternative option are described in Section VII.E of this preamble. The EPA is also seeking comment on different combinations of building blocks and different levels of stringency for each building block.

The EPA is also proposing that measures that a state takes after the date of this proposal, or programs already in place, which result in CO_2 emission reductions during the 2020–2030 period, would apply toward achievement of the state's 2030 CO_2 emission goal. Thus, states with currently existing programs and policies, and states that put in place new programs and policies early, will be better positioned to achieve the goals.

v. Resources for States

To respond to requests from states for methodologies, tools and information to assist them in designing and implementing their plans, the EPA, in consultation with the U.S. Department of Energy and other federal agencies, as well as states, is collecting and developing available resources and is making those resources available to the states via a dedicated Web site.[11] As we and others continue to develop tools, templates and other resources, we will update the Web site. We intend, during the public comment period, to work actively with the states on resources that will be helpful to them in both developing and implementing their plans.

3. Projected National-Level Emission Reductions

Under the proposed guidelines, the EPA projects annual CO_2 reductions of 26 to 30 percent below 2005 levels depending upon the compliance year. These guidelines will also result in important reductions in emissions of criteria air pollutants, including sulfur dioxide (SO_2), nitrogen oxides (NO_X) and directly emitted fine particulate matter ($PM_{2.5}$). A thorough discussion of the EPA's analysis is presented in Section X.A of this preamble and in Chapter 3 of the Regulatory Impact Analysis (RIA) included in the docket for this rulemaking.

4. Costs and Benefits

Actions taken to comply with the proposed guidelines will reduce emissions of CO_2 and other air pollutants, including SO_2, NO_X and directly emitted $PM_{2.5}$, from the electric power industry. States will make the ultimate determination as to how the emission guidelines are implemented. Thus, all costs and benefits reported for this action are illustrative estimates. The EPA has calculated illustrative costs and benefits in two ways: One based on an assumption of individual state plans and another based on an assumption that states will opt for multi-state plans. The illustrative costs and benefits are based upon compliance approaches that reflect a range of measures consisting of improved operations at EGUs, dispatching lower-emitting EGUs and zero-emitting energy sources, and increasing levels of end-use energy efficiency.

Assuming that states comply with the guidelines collaboratively (referred to as the regional compliance approach), the EPA estimates that, in 2020, this proposal will yield monetized climate benefits of approximately $17 billion (2011$) using a 3 percent discount rate (model average) relative to the 2020 base case, as shown in Table 1.[12] The air pollution health co-benefits associated with reducing exposure to ambient $PM_{2.5}$ and ozone through emission reductions of precursor pollutants in 2020 are estimated to be $16 billion to $37 billion using a 3 percent discount rate and $15 billion to $34 billion (2011$) using a 7 percent discount rate relative to the 2020 base case. The annual compliance costs are estimated using the Integrated Planning Model (IPM) and include demand-side energy efficiency program and participant costs as well as monitoring, reporting and recordkeeping costs. In 2020, total compliance costs of this proposal are approximately $5.5 billion (2011$). The quantified net benefits (the difference between monetized benefits and compliance costs) in 2020 are estimated to be $28 billion to $49 billion (2011$) using a 3 percent discount rate (model average). As reflected in Table 2, climate benefits are approximately $30 billion in 2030 using a 3 percent discount rate (model average, 2011$) relative to the 2030 base case assuming a regional compliance approach for the proposal. Health co-benefits are estimated to be approximately $25 to $59 billion (3 percent discount rate) and $23 to $54 billion (7 percent discount rate) relative to the 2030 base case (2011$). In 2030, total compliance costs for the proposed option regional approach are approximately $7.3 billion (2011$). The net benefits for this proposal increase to approximately $48 billion to $82 billion (3 percent discount rate model average, 2011$) in 2030 for the proposed option regional compliance approach.

In comparison, if states choose to comply with the guidelines on a state-specific basis (referred to as state compliance approach), the climate benefits in 2020 are expected to be approximately $18 billion (3 percent discount rate, model average, 2011$), as Table 1 shows. Health co-benefits are estimated to be $17 to $40 billion (3 percent discount rate) and $15 to $36 billion (7 percent discount rate). Total compliance costs are approximately $7.5 billion annually in 2020. Net benefits in 2020 are estimated to be $27 to $50 billion (3 percent model average discount rate, 2011$). In 2030, as shown on Table 2, climate benefits are approximately $31 billion using a 3 percent discount rate (model average, 2011$) relative to the 2030 base case assuming a state compliance approach. Health co-benefits are estimated to be approximately $27 to $62 billion (3 percent discount rate) and $24 to $56 billion (7 percent discount rate) relative to the 2030 base case (2011$). In 2030, total compliance costs for the state approach are approximately $8.8 billion (2011$). In 2030, these net benefits are estimated to be approximately $49 to $84 billion (3 percent discount rate, 2011$) assuming a state compliance approach.

[11] *www2.epa.gov/cleanpowerplantoolbox.*

[12] The EPA has used social cost of carbon (SCC) estimates—i.e., the monetary value of impacts associated with a marginal change in CO_2 emissions in a given year—to analyze CO_2 climate impacts of this rulemaking. The four SCC estimates are associated with different discount rates (model average at 2.5 percent discount rate, 3 percent, and 5 percent; 95th percentile at 3 percent), and each increases over time. In this summary, the EPA provides the estimate of climate benefits associated with the SCC value deemed to be central: The model average at 3 percent discount rate.

TABLE 1—SUMMARY OF THE MONETIZED BENEFITS, COMPLIANCE COSTS, AND NET BENEFITS FOR THE PROPOSED GUIDELINES IN 2020 [a]

[Billions of 2011$]

	3% Discount rate	7% Discount rate
Proposed Guidelines Regional Compliance Approach		
Climate benefits [b]	$17.	
Air pollution health co-benefits [c]	$16 to $37	$15 to $34.
Total Compliance Costs [d]	$5.5	$5.5.
Net Monetized Benefits [e]	$28 to $49	$26 to $45.
Non-monetized Benefits	Direct exposure to SO_2 and NO_2. 1.3 tons of Hg. Ecosystem Effects. Visibility impairment.	
Proposed Guidelines State Compliance Approach		
Climate benefits [b]	$18	
Air pollution health co-benefits [c]	$17 to $40	$15 to $36.
Total Compliance Costs [d]	$7.5	$7.5.
Net Monetized Benefits [e]	$27 to $50	$26 to $46.
Non-monetized Benefits	Direct exposure to SO_2 and NO_2. 1.5 tons. Ecosystem effects. Visibility impairment.	

[a] All estimates are for 2020, and are rounded to two significant figures, so figures may not sum.

[b] The climate benefit estimate in this summary table reflects global impacts from CO_2 emission changes and does not account for changes in non-CO_2 GHG emissions. Also, different discount rates are applied to SCC than to the other estimates because CO_2 emissions are long-lived and subsequent damages occur over many years. The benefit estimates in this table are based on the average SCC estimated for a 3% discount rate, however we emphasize the importance and value of considering the full range of SCC values. As shown in the RIA, climate benefits are also estimated using the other three SCC estimates (model average at 2.5 percent discount rate, 3 percent, and 5 percent; 95th percentile at 3 percent). The SCC estimates are year-specific and increase over time.

[c] The air pollution health co-benefits reflect reduced exposure to $PM_{2.5}$ and ozone associated with emission reductions of directly emitted $PM_{2.5}$, SO_2 and NO_X. The range reflects the use of concentration-response functions from different epidemiology studies. The reduction in premature fatalities each year accounts for over 90 percent of total monetized co-benefits from $PM_{2.5}$ and ozone. These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because the scientific evidence is not yet sufficient to allow differentiation of effect estimates by particle type.

[d] Total costs are approximated by the illustrative compliance costs estimated using the Integrated Planning Model for the proposed guidelines and a discount rate of approximately 5%. This estimate includes monitoring, recordkeeping, and reporting costs and demand side energy efficiency program and participant costs.

[e] The estimates of net benefits in this summary table are calculated using the global social cost of carbon at a 3 percent discount rate (model average). The RIA includes combined climate and health estimates based on these additional discount rates.

TABLE 2—SUMMARY OF THE MONETIZED BENEFITS, COMPLIANCE COSTS, AND NET BENEFITS FOR THE PROPOSED GUIDELINES IN 2030 [a]

[Billions of 2011$]

	3% Discount rate	7% Discount rate
Proposed Guidelines Regional Compliance Approach		
Climate benefits [b]	$30.	
Air pollution health co-benefits [c]	$25 to $59	$23 to $54.
Total Compliance Costs [d]	$7.3	$7.3.
Net Monetized Benefits [e]	$48 to $82	$46 to $77.
Non-monetized Benefits	Direct exposure to SO_2 and NO_2. 1.7 tons of Hg and 580 tons of HCl. Ecosystem Effects. Visibility impairment.	
Proposed Guidelines State Compliance Approach		
Climate benefits [b]	$31.	
Air pollution health co-benefits [c]	$27 to $62	$24 to $56.
Total Compliance Costs [d]	$8.8	$8.8.
Net Monetized Benefits [e]	$49 to $84	$46 to $79.

TABLE 2—SUMMARY OF THE MONETIZED BENEFITS, COMPLIANCE COSTS, AND NET BENEFITS FOR THE PROPOSED GUIDELINES IN 2030 [a]—Continued

[Billions of 2011$]

	3% Discount rate	7% Discount rate
Non-monetized Benefits	Direct exposure to SO_2 and NO_2. 2.1 tons of Hg and 590 tons of HCl. Ecosystem effects. Visibility impairment.	

[a] All estimates are for 2030, and are rounded to two significant figures, so figures may not sum.

[b] The climate benefit estimate in this summary table reflects global impacts from CO_2 emission changes and does not account for changes in non-CO_2 GHG emissions. Also, different discount rates are applied to SCC than to the other estimates because CO_2 emissions are long-lived and subsequent damages occur over many years. The benefit estimates in this table are based on the average SCC estimated for a 3% discount rate, however we emphasize the importance and value of considering the full range of SCC values. As shown in the RIA, climate benefits are also estimated using the other three SCC estimates (model average at 2.5 percent discount rate, 3 percent, and 5 percent; 95th percentile at 3 percent). The SCC estimates are year-specific and increase over time.

[c] The air pollution health co-benefits reflect reduced exposure to $PM_{2.5}$ and ozone associated with emission reductions of directly emitted $PM_{2.5}$, SO_2 and NO_X. The range reflects the use of concentration-response functions from different epidemiology studies. The reduction in premature fatalities each year accounts for over 90 percent of total monetized co-benefits from $PM_{2.5}$ and ozone. These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because the scientific evidence is not yet sufficient to allow differentiation of effect estimates by particle type.

[d] Total costs are approximated by the illustrative compliance costs estimated using the Integrated Planning Model for the proposed guidelines and a discount rate of approximately 5%. This estimate includes monitoring, recordkeeping, and reporting costs and demand side energy efficiency program and participant costs.

[e] The estimates of net benefits in this summary table are calculated using the global social cost of carbon at a 3 percent discount rate (model average). The RIA includes combined climate and health estimates based on these additional discount rates.

There are additional important benefits that the EPA could not monetize. These unquantified benefits include climate benefits from reducing emissions of non-CO_2 greenhouse gases (e.g., nitrous oxide and methane) [13] and co-benefits from reducing direct exposure to SO_2, NO_X and hazardous air pollutants (e.g., mercury and hydrogen chloride), as well as from reducing ecosystem effects and visibility impairment.

In addition to the cost and benefits of the rule, the EPA projects the employment impacts of the guidelines. We project job gains and losses relative to base case for the electric generation, coal and natural gas production, and demand side energy efficiency sectors. In 2020, we project job growth of 25,900 to 28,000 job-years [14] in the power production and fuel extraction sectors, and we project an increase of 78,800 jobs in the demand-side energy efficiency sector.

Based upon the foregoing, it is clear that the monetized benefits of this proposal are substantial and far outweigh the costs.

B. Organization and Approach for This Proposed Rule

This action presents the EPA's proposed emission guidelines for states to consider in developing plans to reduce GHG emissions from the electric power sector. Section II provides background on climate change impacts from GHG emissions, GHG emissions from fossil fuel-fired EGUs and the utility power sector and CAA section 111(d) requirements. Section III presents a summary of the EPA's stakeholder outreach efforts, key messages provided by stakeholders, state policies and programs that reduce GHG emissions, and conclusions. In Section IV of the preamble, we present a summary of the rule requirements and the legal basis for these. Section V explains the EPA authority to regulate CO_2 and EGUs, identifies affected sources, and describes the proposed treatment of source categories. Section VI describes the use of building blocks for setting state goals and key considerations in doing so. Sections VII and VIII provide explanations of the proposed state-specific goals and the proposed requirements for state plans, respectively. Implications for the new source review and Title V programs and potential interactions with other EPA rules are described in Section IX. Impacts of the proposed action are then described in Section X, followed by a discussion of statutory and executive order reviews in Section XI and the statutory authority for this action in Section XII.

We note that this rulemaking overlaps in certain respects with two other related rulemakings: The January 2014 proposed rulemaking that the EPA published on January 8, 2014 for CO_2 emissions from newly constructed affected sources,[15] and the rulemaking for modified and reconstructed sources that the EPA is proposing at the same time as this rulemaking. Each of these three rulemakings is independent of the other two, and each has its own rulemaking docket. Accordingly, commenters who wish to comment on any aspect of this rulemaking, including a topic that overlaps an aspect of one or both of the other two related rulemakings, should make those comments on this rulemaking.

II. Background

In this section, we discuss climate change impacts from GHG emissions, both on public health and public welfare, present information about GHG emissions from fossil fuel fired EGUs, and summarize the statutory and regulatory requirements relevant to this rulemaking.

A. Climate Change Impacts From GHG Emissions

In 2009, the EPA Administrator issued the document known as the Endangerment Finding under CAA section 202(a)(1).[16] In the Endangerment Finding, which focused on public health and public welfare impacts within the United States, the Administrator found that elevated concentrations of GHGs in the atmosphere may reasonably be anticipated to endanger public health and welfare of current and future generations. We summarize these adverse effects on public health and welfare briefly here.

1. Public Health Impacts Detailed in the 2009 Endangerment Finding

Climate change caused by human emissions of GHGs threatens public health in multiple ways. By raising average temperatures, climate change

[13] Although CO_2 is the predominant greenhouse gas released by the power sector, electricity generating units also emit small amounts of nitrous oxide and methane. See RIA Chapter 2 for more detail about power sector emissions and the U.S. Greenhouse Gas Reporting Program's power sector summary, *http://www.epa.gov/ghgreporting/ghgdata/reported/powerplants.html.*

[14] A job-year is not an individual job; rather, a job-year is the amount of work performed by the equivalent of one full-time individual for one year. For example, 20 job-years in 2020 may represent 20 full-time jobs or 40 half-time jobs.

[15] 79 FR 1430.

[16] ''Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act,'' 74 FR 66,496 (Dec. 15, 2009) (''Endangerment Finding'').

increases the likelihood of heat waves, which are associated with increased deaths and illnesses. While climate change also increases the likelihood of reductions in cold-related mortality, evidence indicates that the increases in heat mortality will be larger than the decreases in cold mortality in the United States. Compared to a future without climate change, climate change is expected to increase ozone pollution over broad areas of the U.S., including in the largest metropolitan areas with the worst ozone problems, and thereby increase the risk of morbidity and mortality. Other public health threats also stem from projected increases in intensity or frequency of extreme weather associated with climate change, such as increased hurricane intensity, increased frequency of intense storms, and heavy precipitation. Increased coastal storms and storm surges due to rising sea levels are expected to cause increased drownings and other health impacts. Children, the elderly, and the poor are among the most vulnerable to these climate-related health effects.

2. Public Welfare Impacts Detailed in the 2009 Endangerment Finding

Climate change caused by human emissions of GHGs also threatens public welfare in multiple ways. Climate changes are expected to place large areas of the country at serious risk of reduced water supplies, increased water pollution, and increased occurrence of extreme events such as floods and droughts. Coastal areas are expected to face increased risks from storm and flooding damage to property, as well as adverse impacts from rising sea level, such as land loss due to inundation, erosion, wetland submergence and habitat loss. Climate change is expected to result in an increase in peak electricity demand, and extreme weather from climate change threatens energy, transportation, and water resource infrastructure. Climate change may exacerbate ongoing environmental pressures in certain settlements, particularly in Alaskan indigenous communities. Climate change also is very likely to fundamentally rearrange U.S. ecosystems over the 21st century. Though some benefits may balance adverse effects on agriculture and forestry in the next few decades, the body of evidence points towards increasing risks of net adverse impacts on U.S. food production, agriculture and forest productivity as temperature continues to rise. These impacts are global and may exacerbate problems outside the U.S. that raise humanitarian, trade, and national security issues for the U.S.

3. New Scientific Assessments

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

The EPA has reviewed these new assessments and finds that the improved understanding of the climate system they present strengthens the case that GHGs endanger public health and welfare.

In addition, these assessments highlight the urgency of the situation as the concentration of CO_2 in the atmosphere continues to rise. Absent a reduction in emissions, a recent National Research Council of the National Academies assessment projected that concentrations by the end of the century would increase to levels that the Earth has not experienced for millions of years.[17] In fact, that assessment stated that ''the magnitude and rate of the present greenhouse gas increase place the climate system in what could be one of the most severe increases in radiative forcing of the global climate system in Earth history.''[18]

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

> Emissions of carbon dioxide from the burning of fossil fuels have ushered in a new epoch where human activities will largely determine the evolution of Earth's climate. Because carbon dioxide in the atmosphere is long lived, it can effectively lock Earth and future generations into a range of impacts, some of which could become very severe. Therefore, emission reductions choices made today matter in determining impacts experienced not just over the next few decades, but in the coming centuries and millennia.[19]

Moreover, due to the time-lags inherent in the Earth's climate, the Climate Stabilization Targets assessment notes that the full warming from any given concentration of CO_2 reached will not be realized for several centuries.

The recently released USGCRP ''Climate Change Impacts'' assessment[20] emphasizes that climate change is already happening now and it is happening in the United States. The assessment documents the increases in some extreme weather and climate events in recent decades, the damage and disruption to infrastructure and agriculture, and projects continued increases in impacts across a wide range of peoples, sectors, and ecosystems.

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

Finally, it should be noted that the concentration of carbon dioxide in the atmosphere continues to rise dramatically. In 2009, the year of the Endangerment Finding, the average concentration of carbon dioxide as

[17] National Research Council, Understanding Earth's Deep Past, p. 1.

[18] Id., p.138.

[19] National Research Council, Climate Stabilization Targets, p. 3.

[20] U.S. Global Change Research Program, Climate Change Impacts in the United States: The Third National Climate Assessment, May 2014 Available at *http://nca2014.globalchange.gov/.*

measured on top of Mauna Loa was 387 parts per million.[21] The average concentration in 2013 was 396 parts per million. And the monthly concentration in April of 2014 was 401 parts per million, the first time a monthly average has exceeded 400 parts per million since record keeping began at Mauna Loa in 1958, and for at least the past 800,000 years according to ice core records.[22]

B. GHG Emissions From Fossil Fuel-Fired EGUs

Fossil fuel-fired electric utility generating units (EGUs) are by far the largest emitters of GHGs, primarily in the form of CO_2, among stationary sources in the U.S., and among fossil fuel-fired units, coal-fired units are by far the largest emitters. This section describes the amounts of those emissions and places those amounts in the context of the national inventory of GHGs.

The EPA prepares the official U.S. Inventory of Greenhouse Gas Emissions and Sinks [23] (the U.S. GHG Inventory) to comply with commitments under the United Nations Framework Convention on Climate Change (UNFCCC). This inventory, which includes recent trends, is organized by industrial sectors. It provides the information in Table 3 below, which presents total U.S. anthropogenic emissions and sinks [24] of GHGs, including CO_2 emissions, for the years 1990, 2005 and 2012.

TABLE 3—U.S. GHG EMISSIONS AND SINKS BY SECTOR

[Teragram carbon dioxide equivalent (Tg CO_2 Eq.)] [25]

Sector	1990	2005	2012
Energy	5,260.1	6,243.5	5,498.9
Industrial Processes	316.1	334.9	334.4
Solvent and Other Product Use	4.4	4.4	4.4
Agriculture	473.9	512.2	526.3
Land Use, Land-Use Change and Forestry	13.7	25.5	37.8
Waste	165.0	133.2	124.0
Total Emissions	6,233.2	7,253.8	6,525.6
Land Use, Land-Use Change and Forestry (Sinks)	(831.3)	(1,030.7)	(979.3)
Net Emissions (Sources and Sinks)	5,402.1	6,223.1	5,546.3

Total fossil energy-related CO_2 emissions (including both stationary and mobile sources) are the largest contributor to total U.S. GHG emissions, representing 77.7 percent of total 2012 GHG emissions.[26] In 2012, fossil fuel combustion by the electric power sector—entities that burn fossil fuel and whose primary business is the generation of electricity—accounted for 38.7 percent of all energy-related CO_2 emissions.[27] Table 4 below presents total CO_2 emissions from fossil fuel-fired EGUs, for years 1990, 2005 and 2012.

TABLE 4—U.S. GHG EMISSIONS FROM GENERATION OF ELECTRICITY FROM COMBUSTION OF FOSSIL FUELS

[Tg CO_2] [28]

GHG emissions	1990	2005	2012
Total CO_2 from fossil fuel combustion EGUs	1,820.8	2,402.1	2,022.7
—from coal	1,547.6	1,983.8	1,511.2
—from natural gas	175.3	318.8	492.2
—from petroleum	97.5	99.2	18.8

C. The Utility Power Sector

Electricity in the United States is generated by a range of sources—from power plants that use fossil fuels like coal, oil, and natural gas, to non-fossil sources, such as nuclear, solar, wind and hydroelectric power. In 2013, over 67 percent of power in the U.S. was generated from the combustion of coal, natural gas, and other fossil fuels, over 40 percent from coal and over 26 percent from natural gas.[29] In recent years, though, the proportion of new renewable generation coming on line has increased dramatically. For instance, over 38 percent of new generating capacity (over 5 GW out of 13.5 GW) built in 2013 used renewable power generation technologies.[30]

[21] *ftp://aftp.cmdl.noaa.gov/products/trends/co2/co2_annmean_mlo.txt.*

[22] *http://www.esrl.noaa.gov/gmd/ccgg/trends/.*

[23] ''Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2012'', Report EPA 430–R–14–003, United States Environmental Protection Agency, April 15, 2014.

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

[25] From Table ES–4 of ''Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2012, Report EPA 430–R–14–003, United States Environmental Protection Agency, April 15, 2014.

[26] From Table ES–2 ''Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2012'', Report EPA 430–R–14–003, United States Environmental Protection Agency, April 15, 2014.

[27] From Table 3–1 ''Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2012'', Report EPA 430–R–14–003, United States Environmental Protection Agency, April 15, 2014.

[28] From Table 3–5 ''Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2012'', Report EPA 430–R–14–003, United States Environmental Protection Agency, April 15, 2014.

[29] U.S. Energy Information Administration (EIA), ''Table 7.2b Electricity Net Generation: Electric Power Sector Electric Power Sector,'' data from April 2014 Monthly Energy Review, release date April 25, 2014. Available at: *http://www.eia.gov/totalenergy/data/browser/xls.cfm?tbl=T07.02B&freq=m.*

[30] Based on Table 6.3 (New Utility Scale Generating Units by Operating Company, Plant, Month, and Year) of the U.S. Energy Information Administration (EIA) Electric Power Monthly, data for December 2013, for the following renewable

Continued

This range of different power plants generates electricity that is transmitted and distributed through a complex system of interconnected components to industrial, business, and residential consumers.

The utility power sector is unique in that, unlike other sectors where the sources operate independently and on a local scale, power sources operate in a complex, interconnected grid system that typically is regional in scale. In addition, the U.S. economy depends on this sector for a reliable supply of power at a reasonable cost.

In the U.S., much of the existing power generation fleet in the infrastructure is aging. There has been, and continues to be, technological advancement in many areas, including energy efficiency, solar power generation, and wind power generation. Advancements and innovation in power sector technologies provide the opportunity to address CO_2 emission levels at affected power plants while at the same time improving the overall power system in the U.S. by lowering the carbon intensity of power generation, and ensuring a continued reliable supply of power at a reasonable cost.

D. Statutory and Regulatory Requirements

Clean Air Act section 111, which Congress enacted as part of the 1970 Clean Air Act Amendments, establishes mechanisms for controlling emissions of air pollutants from stationary sources. This provision requires the EPA to promulgate a list of categories of stationary sources that the Administrator, in his or her judgment, finds ''causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare.'' [31] The EPA has listed more than 60 stationary source categories under this provision.[32] Once the EPA lists a source category, the EPA must, under CAA section 111(b)(1)(B), establish ''standards of performance'' for emissions of air pollutants from new sources in the source categories.[33] These standards are known as new source performance standards (NSPS), and they are national requirements that apply directly to the sources subject to them.

When the EPA establishes NSPS for new sources in a particular source category, the EPA is also required, under CAA section 111(d)(1), to prescribe regulations for states to submit plans regulating existing sources in that source category for any air pollutant that, in general, is not regulated under the CAA section 109 requirements for the NAAQS or regulated under the CAA section 112 requirements for hazardous air pollutants (HAP). CAA section 111(d)'s mechanism for regulating existing sources differs from the one that CAA section 111(b) provides for new sources because CAA section 111(d) contemplates states submitting plans that establish ''standards of performance'' for the affected sources and that contain other measures to implement and enforce those standards.

''Standards of performance'' are defined under CAA section 111(a)(1) as standards for emissions that reflect the emission limitation achievable from the ''best system of emission reduction,'' considering costs and other factors, that ''the Administrator determines has been adequately demonstrated.'' CAA section 111(d)(1) grants states the authority, in applying a standard of performance to particular sources, to take into account the source's remaining useful life or other factors.

Under CAA section 111(d), a state must submit its plan to the EPA for approval, and the EPA must approve the state plan if it is ''satisfactory.'' [34] If a state does not submit a plan, or if the EPA does not approve a state's plan, then the EPA must establish a plan for that state.[35] Once a state receives the EPA's approval for its plan, the provisions in the plan become federally enforceable against the entity responsible for noncompliance, in the same manner as the provisions of an approved SIP under CAA section 110. Although affected EGUs located in Indian country operate as part of the interconnected system of electricity production and distribution, those EGUs would not be encompassed within a state's CAA section 111(d) plan. Instead, a tribe that has one or more affected EGUs located in its area of Indian country [36] would have the opportunity, but not the obligation, to establish a plan that establishes standards of performance for CO_2 emissions from affected EGUs for its tribal lands.

The EPA issued regulations implementing CAA section 111(d) in 1975,[37] and has revised them in the years since.[38] (We refer to the regulations generally as the implementing regulations, and we refer to the 1975 rulemaking as the framework regulations.) These regulations provide that, in promulgating requirements for sources under CAA section 111(d), the EPA first develops regulations known as ''emission guidelines,'' which establish binding requirements that states must address when they develop their plans.[39] The implementing regulations also establish timetables for state and EPA action: States must submit state plans within 9 months of the EPA's issuance of the guidelines,[40] and the EPA must take final action on the state plans within 4 months of the due date for those plans,[41] although the EPA has authority to extend those deadlines.[42] In the present rulemaking, the EPA is following the requirements of the implementing regulations, and is not re-opening them, except that the EPA is extending the timetables, as described below.

Over the last forty years, under CAA section 111(d), the agency has regulated four pollutants from five source categories (i.e., sulfuric acid plants (acid mist), phosphate fertilizer plants (fluorides), primary aluminum plants (fluorides), Kraft pulp plants (total reduced sulfur), and municipal solid waste landfills (landfill gases)).[43] In addition, the agency has regulated additional pollutants under CAA section 111(d) in conjunction with CAA

energy sources: solar, wind, hydro, geothermal, landfill gas, and biomass. Available at: *http://www.eia.gov/electricity/monthly/epm_table_grapher.cfm?t=epmt_6_03.*

[31] CAA § 111(b)(1)(A).

[32] See 40 CFR 60 subparts Cb–OOOO.

[33] CAA § 111(b)(1)(B), 111(a)(1).

[34] CAA section 111(d)(2)(A).

[35] CAA section 111(d)(2)(A).

[36] The EPA is aware of at least four affected sources located in Indian Country: Two on Navajo lands—the Navajo Generating Station and the Four Corners Generating Station; one on Ute lands—the Bonanza Generating Station; and one on Fort Mojave lands, the South Point Energy Center. The affected EGUs at the first three plants are coal-fired EGUs. The fourth affected EGU is an NGCC facility.

[37] ''State Plans for the Control of Certain Pollutants From Existing Facilities,'' 40 FR 53,340 (Nov. 17, 1975).

[38] The most recent amendment was in 77 FR 9304 (Feb. 16, 2012).

[39] 40 CFR 60.22. In the 1975 rulemaking, the EPA explained that it used the term ''emissions guidelines''—instead of emissions limitations—to make clear that guidelines would not be binding requirements applicable to the sources, but instead are ''criteria for judging the adequacy of State plans.'' 40 FR at 53,343.

[40] 40 CFR 60.23(a)(1).

[41] 40 CFR 60.27(b).

[42] *See 40 CFR 60.27(a).*

[43] *See* ''Phosphate Fertilizer Plants; Final Guideline Document Availability,'' 42 Fed. Reg. 12,022 (Mar. 1, 1977); ''Standards of Performance for New Stationary Sources; Emission Guideline for Sulfuric Acid Mist,'' 42 FR 55,796 (Oct. 18, 1977); ''Kraft Pulp Mills, Notice of Availability of Final Guideline Document,'' 44 FR 29,828 (May 22, 1979); ''Primary Aluminum Plants; Availability of Final Guideline Document,'' 45 FR 26,294 (Apr. 17, 1980); ''Standards of Performance for New Stationary Sources and Guidelines for Control of Existing Sources: Municipal Solid Waste Landfills, Final Rule,'' 61 FR 9905 (Mar. 12, 1996).

section 129.[44] The agency has not previously regulated CO_2 or any other greenhouse gas under CAA section 111(d).

The EPA's previous CAA section 111(d) actions were necessarily geared toward the pollutants and industries regulated. Similarly, in this proposed rulemaking, in defining CAA section 111(d) emission guidelines for the states and determining the BSER, the EPA believes that taking into account the particular characteristics of carbon pollution, the interconnected nature of the power sector and the manner in which EGUs are currently operated is warranted. Specifically, the operators themselves treat increments of generation as interchangeable between and among sources in a way that creates options for relying on varying utilization levels, lowering carbon generation, and reducing demand as components of the overall method for reducing CO_2 emissions. Doing so results in a broader, forward-thinking approach to the design of programs to yield critical CO_2 reductions that improve the overall power system by lowering the carbon intensity of power generation, while offering continued reliability and cost-effectiveness. These opportunities exist in the power sector in ways that were not relevant or available for other industries for which the EPA has established CAA section 111(d) emission guidelines.[45]

In this action, the EPA is proposing emission guidelines for states to follow in developing their plans to reduce emissions of CO_2 from the electric power sector.

III. Stakeholder Outreach and Conclusions

A. Stakeholder Outreach

1. The President's Call for Engagement

Following the direction of the Presidential Memorandum to the Administrator (June 25, 2013),[46] this proposed rule was developed after extensive and vigorous outreach to stakeholders and the general public. The Presidential Memorandum instructed the Administrator to inaugurate the process for developing standards through direct engagement with the states and a full range of stakeholders:

> Launch this effort through direct engagement with States, as they will play a central role in establishing and implementing standards for existing power plants, and, at the same time, with leaders in the power sector, labor leaders, non-governmental organizations, other experts, tribal officials, other stakeholders, and members of the public, on issues informing the design of the program.

2. Educating the Public and Stakeholder Outreach

To carry out this stakeholder outreach, the EPA embarked on an unprecedented pre-proposal outreach effort. From consumer groups to states to power plant owner/operators to technology innovators, the EPA sought input from all perspectives.

The EPA began the outreach efforts with a webinar and associated teleconferences to establish a common understanding of the basic requirements and process of CAA section 111(d). The August 27, 2013 overview presentation was offered as a webinar for state and tribal officials, ''Building a Common Understanding: Clean Air Act and Upcoming Carbon Pollution Guidelines for Existing Power Plants.''

The EPA followed up on the presentation by offering four national teleconference calls with representatives from states, tribes, industry, environmental justice organizations, community organizations and environmental representatives. The teleconferences offered a venue for stakeholders to ask questions of the EPA about the overview presentation and for the EPA to gather initial reactions from stakeholders. Stakeholders and members of the public continued to view and refer to the overview presentation throughout the outreach process. By May 2014, the presentation had been viewed more than 5,600 times.

The agency also provided mechanisms for anyone from the public to provide input during the pre-proposal development of this action. The EPA set up two user-friendly options to accept input during the pre-proposal period—email and a web-based form. The EPA has received more than 2,000 emails offering input into the development of these guidelines.

These emails and other materials provided to the EPA are posted on line as part of a non-regulatory docket, EPA Docket ID No. EPA–HQ–OAR–2014–0020, at *www.regulations.gov.* All of the documents on which this proposal is based are available at Docket ID No. EPA–HQ–OAR–2013–0602, at *www.regulations.gov.* However, while the information collected through extensive outreach helped the agency formulate this proposal, we are not relying on all of the documents, emails, and other information included in the informational docket that was established as a part of that outreach effort, nor will the EPA be responding to specific comments or issues raised during the outreach effort. Rather, we have included in the docket for this proposal all of the information we relied on for this action.

The agency has encouraged, organized, and participated in hundreds of meetings about CAA section 111(d) and reducing carbon pollution from existing power plants. Attendees at these various meetings have included states and tribes, members of the public, and representatives from multiple industries, labor leaders, environmental groups and other non-governmental organizations. The direct engagement has brought together a variety of states and stakeholders to discuss a wide range of issues related to the electricity sector and the development of emission guidelines under CAA section 111(d). The meetings occurred in Washington, DC, and at locations across the country. The meetings were attended by the EPA Regional Administrators, managers and staff and who are playing or will play key roles in developing and implementing the rule.

Part of this effort included the agency's holding of 11 public listening sessions; one national listening session in Washington, DC and 10 listening sessions in locations in the EPA regional offices across the country. All of the outreach meetings were designed to solicit policy ideas, concerns and technical information from stakeholders about using CAA section 111(d).

This outreach process has produced a wealth of information which has informed this proposal significantly. The pre-proposal outreach efforts far exceeded what is required of the agency in the normal course of a rulemaking process, and the EPA expects that the dialog with states and stakeholders will continue throughout the process and even after the rule is finalized. The EPA recognizes the importance of working with all stakeholders, and in particular with the states, to ensure a clear and common understanding of the role the

[44] *See, e.g.,* ''Standards of Performance for New Stationary Sources and Emission Guidelines for Existing Sources: Sewage Sludge Incineration Units, Final Rule,'' 76 FR 15,372 (Mar. 21, 2011).

[45] *See* ''Phosphate Fertilizer Plants; Final Guideline Document Availability,'' 42 FR 12,022 (Mar. 1, 1977); ''Standards of Performance for New Stationary Sources; Emission Guideline for Sulfuric Acid Mist,'' 42 FR 55,796 (Oct. 18, 1977); ''Kraft Pulp Mills, Notice of Availability of Final Guideline Document,'' 44 FR 29,828 (May 22, 1979); ''Primary Aluminum Plants; Availability of Final Guideline Document,'' 45 FR 26,294 (Apr. 17, 1980); ''Standards of Performance for New Stationary Sources and Guidelines for Control of Existing Sources: Municipal Solid Waste Landfills, Final Rule,'' 61 F R 9905 (Mar. 12, 1996).

[46] Presidential Memorandum—Power Sector Carbon Pollution Standards, June 25, 2013. *http://www.whitehouse.gov/the-press-office/2013/06/25/presidential-memorandum-power-sector-carbon-pollution-standards.*

states will play in addressing carbon pollution from power plants.

3. Public Listening Sessions

More than 3,300 people attended the public listening sessions held in 11 cities across the country. Holding the listening sessions at the EPA's regional offices offered thousands of people from different parts of the country the opportunity to provide input to EPA officials in accessible venues. In addition to being well located, holding the sessions in regional offices also allowed the agency to use resources prudently and enabled a variety of the EPA staff involved in the development and ultimate implementation of this upcoming rule to attend and learn from the views expressed.

More than 1,600 people spoke at the 11 listening sessions. Speakers included Members of Congress, other public officials, industry representatives, faith-based organizations, unions, environmental groups, community groups, students, public health groups, energy groups, academia and concerned citizens. Participants shared a range of perspectives. Many were concerned by the impacts of climate change on their health and on future generations, others worried about the impact of regulations on the economy. Their support for the agency's efforts varied.

Summaries of these 11 public listening sessions are available at *www.regulations.gov* at EPA Docket ID No. EPA–HQ–OAR–2014–0020.

4. State Officials

Since fall 2013, the agency provided multiple opportunities for the states to inform this proposal. In addition, the EPA organized, encouraged and attended meetings to discuss multi-state planning efforts. Because of the interconnectedness of the power sector, and the fact that electricity generated at power plants crosses state lines, states, utilities and ratepayers may benefit from states working together to address the requirements of this rulemaking implementation. The meetings provided state leaders, including governors, environmental commissioners, energy officers, public utility commissioners, and air directors, opportunities to engage with the EPA officials.

Agency officials listened to ideas, concerns and details from states, including from states with a wide range of experience in reducing carbon pollution from power plants. The agency has collected policy papers from states with overarching energy goals and technical details on the states' electricity sector. The agency has engaged, and will continue to engage with, all of the 50 states throughout the rulemaking process.

5. Tribal Officials

The EPA conducted significant outreach to tribes, who are not required to—but may—develop or adopt Clean Air Act programs. The EPA is aware of three coal-fired power plants and one natural gas-fired EGU located in Indian country but is not aware of any EGUs that are owned or operated by tribal entities.

The EPA conducted outreach to tribal environmental staff and offered consultation with tribal officials in developing this action. Because the EPA is aware of tribal interest in this proposed rule, the EPA offered consultation with tribal officials early in the process of developing the proposed regulation to permit tribes to have meaningful and timely input into its development.

The EPA sent consultation letters to 584 tribal leaders. The letters provided information regarding the EPA's development of emission guidelines for existing power plants and offered consultation. None have requested consultation. Tribes were invited to participate in the national informational webinar held August 27, 2013. In addition, a consultation/outreach meeting was held on September 9, 2013, with tribal representatives from some of the 584 tribes. The EPA representatives also met with tribal environmental staff with the National Tribal Air Association, by teleconference, on December 19, 2013. In those teleconferences, the EPA provided background information on the GHG emission guidelines to be developed and a summary of issues being explored by the agency.

In addition, the EPA held a series of listening sessions prior to development of this proposed action. Tribes participated in a session on September 9, 2013 with the state agencies, as well as in a separate session with tribes on September 26, 2013.

6. Industry Representatives

Agency officials have engaged with industry leaders and representatives from trade associations in scores of one-on-one and national meetings. Many meetings occurred at the EPA headquarters and in the EPA's Regional Offices and some were sponsored by stakeholder groups. Because the focus of the standard is on the electricity sector, many of the meetings with industry have been with utilities and industry representatives directly related to the electricity sector. The agency has also met with energy industries such as coal and natural gas interests, as well as companies that offer new technology to prevent or reduce carbon pollution, including companies that have expertise in renewable energy and energy efficiency. Other meetings have been held with representatives of energy intensive industries, such as the iron and steel and aluminum industries to help understand the issues related to large industrial users of electricity.

7. Electric Utility Representatives

Agency officials participated in many meetings with utilities and their associations. The meetings focused on the importance of the utility industry in reducing carbon emissions from power plants. Power plant emissions are central to this rulemaking. The EPA encouraged industry representatives to work with state environmental and energy officers.

The electric utility representatives included private utilities or investor owned utilities. Public utilities and cooperative utilities were also part of in-depth conversations about CAA section 111(d) with EPA officials.

The conversations included meetings with the EPA headquarters and Regional offices. State officials were included in many of the meetings. Meetings with utility associations and groups of utilities were held with key EPA officials. The meetings covered technical, policy, and legal topics of interest and utilities expressed a wide variety of support and concerns about CAA section 111(d).

8. Electricity Grid Operators

The EPA had a number of conversations with the Independent System Operators and Regional Transmission Organizations (ISOs and RTOs) to discuss the rule and issues related to grid operations and reliability. EPA staff met with the ISO/RTO Council on several occasions to collect their ideas. The EPA Regional Offices also met with the ISOs and RTOs in their regions. System operators have offered suggestions in using regional approaches to implement CAA section 111(d) while maintaining reliable, affordable electricity.

9. Representatives From Non-Governmental Organizations

Agency officials engaged with representatives of environmental justice organizations during the outreach effort, for example, we engaged with the National Environmental Justice Advisory Council members in September 2013. The NEJAC is composed of stakeholders, including environmental justice leaders and other leaders from state and local government and the private sector.

The EPA has also met with a number of environmental groups to provide their ideas on how to reduce carbon pollution from existing power plants using section 111(d) of the CAA.

Many environmental organizations discussed the need for reducing carbon pollution. Meetings were technical, policy and legal in nature and many groups discussed specific state policies that are already in place to reduce carbon pollution in the states.

A number of organizations representing religious groups have reached out to the EPA on several occasions to discuss their concerns and ideas regarding this rule.

Public health groups discussed the need for protection of children's health from harmful air pollution. Doctors and health care providers discussed the link between reducing carbon pollution and air pollution and public health. Consumer groups representing advocates for low income electricity customers discussed the need for affordable electricity. They talked about reducing electricity prices for consumers through energy efficiency and low cost carbon reductions.

10. Labor

EPA senior officials and staff met with a number of labor union representatives about reducing carbon pollution using CAA section 111(d). Those unions included: The United Mine Workers of America; the Sheet Metal, Air, Rail and Transportation Union (SMART); the International Brotherhood of Boilermakers, Iron Ship Builders, Blacksmiths, Forgers and Helpers (IBB); United Association of Journeymen and Apprentices of the Plumbing and Pipe Fitting Industry of the United States and Canada; the International Brotherhood of Electrical Workers (IBEW): And the Utility Workers Union of America. In addition, agency leaders met with the Presidents of several unions and the President of the American Federation of Labor-Congress of Industrial Organizations (AFL–CIO) at the AFL–CIO headquarters.

EPA officials, when invited, attended meetings sponsored by labor unions to give presentations and engage in discussions about reducing carbon pollution using CAA section 111(d). These included meetings sponsored by the IBB and the IBEW.

B. Key Messages From Stakeholders

Many stakeholders stated that opportunities exist to reduce the carbon emissions from existing power generation through a wide range of measures, from measures that are implementable via physical changes at the source to those that also are implementable across the broader power generation system. Opinions varied about how broader system measures could factor into programs to reduce carbon pollution. Some stakeholders recommended that system-wide measures be allowed for compliance, but not factored into the carbon improvement goals the EPA establishes, while others recommended that system-wide measures be factored into the goals. Among the arguments and information offered by stakeholders who suggested that states be encouraged to incorporate system-wide measures into their state plans and that EGU operators be encouraged to rely on such measures were examples and discussions of the significant extent to which dispatch, end use energy efficiency and renewable energy had already proven to be successful strategies for reducing EGU CO_2 emissions. Some state and industry representatives favored goals that they described as based on measures implementable only within the facility ''fence line'' (i.e., measures implementable only at the source). Many stakeholders stated that the EPA should not require the state plans to impose on the affected EGUs legal responsibility for the full amount of required CO_2 emissions reductions, and instead, the EPA should authorize the state plans to include requirements on entities other than the affected EGUs that would have the effect of reducing utilization and, therefore, emissions from the affected EGUs.

Views on the form and stringency of the goal or guidelines varied. Some stakeholders preferred a rate-based form of the goal, while others preferred a mass-based form. In addition, some stakeholders recommended that the EPA let the states have the flexibility to either choose among multiple forms of the goals or to set their own goals. With regard to the stringency of the goal, some stakeholders recommended that the stringency of the goals vary by state, to account for differences in state circumstances.

Many stakeholders recognized the value of allowing states flexibility in implementing the goals the EPA establishes. For example, states highlighted the importance of the EPA recognizing existing state and regional programs that address carbon pollution, including market-based programs, and allowing credit for prior accomplishments in reducing CO_2 emissions. Many states and other stakeholders noted the importance of the EPA allowing flexibility in compliance options such that states could use approaches such as demand-side management to attain the goals.

Many stakeholders recommended that states be allowed to develop multi-state programs. It was frequently noted that such regional approaches could offer cost-effective carbon pollution solutions.

There was broad agreement that most states would need more than one year to develop and submit their complete plans to the EPA. For some states, more time is necessary because of the state legislative schedule and/or regulatory process. In some cases, approval of a plan through a state's legislative or regulatory process could take one year or more after the plan has already been developed. Additional time would also allow and encourage multi-state and regional partnerships and programs.

Many stakeholders also supported flexibility in the timing of implementation of the state plans and power sector compliance with the goals in the state plans. Such flexibility, some stakeholders asserted, would accommodate the diverse GHG mitigation potential of states and support more cost-effective approaches to achieving CO_2 reductions.

During the outreach process, some stakeholders raised general concerns that the rulemaking could have a negative impact on jobs and ratepayers. Some stakeholders also expressed concerns about potential adverse effects on electric system reliability. Some stakeholders were concerned that meeting the goals could potentially result in stranded generation assets. To prevent this from occurring, some stakeholders suggested varying the stringency of standards to account for individual state circumstances and variation.

The EPA has given stakeholder input careful consideration during the development of this proposal and, as a result, this proposal includes features that are intended to be responsive to many stakeholder concerns.

C. Key Stakeholder Proposals

During the EPA's public outreach in advance of this proposal, a number of ideas were put forward that are not fully reflected in this proposal. We invite public comment on these ideas, some of which are outlined below.

1. Model Rule on Interstate Emissions Credit Trading and Price Ceiling

Some groups thought that the EPA should put forward a model rule for an interstate emissions credit trading program that could be easily adopted by states who wanted to use such a program for its plan. One group suggested the model rule should include a provision to allow the state to compensate merchant generators as well as retail rate payers. Another group specified that the model rule would also include a ceiling-price called an alternative compliance payment that would fund state directed clean technology investment. Facilities that face costs that exceed the ceiling price could opt to pay into the fund as a way of complying.

2. Equivalency Tests

One group recommended that state programs be allowed to demonstrate equivalency using one of three tests: Rate-based equivalency via a demonstration that the state program achieves equivalent or better carbon intensity for the regulated sector; mass-based equivalency via a demonstration that the program achieves equal or greater emission reductions relative to what would be achieved by the federal approach; or a market price-based equivalency via a demonstration that the program reflects a carbon price comparable to or greater than the cost-effectiveness benchmark used by the EPA in designing the program. The EPA is proposing a way to demonstrate equivalency and that is discussed in Section VIII of this preamble.

3. Power Plant-Specific Assessment

Other stakeholders suggested that an ''inside the fence'' plant- or unit-specific assessment linked to the availability of control at the source such as heat rate improvements should be considered. They indicated that once plant-specific goals are established based on on-site CO_2 reduction opportunities, the source should have the flexibility to look ''outside the fence'' for the means to achieve the goals, including the use of emissions trading, and averaging.

The EPA invites comment on these suggestions.

D. Consideration of the Range of Existing State Policies and Programs

Across the nation, many states and regions have shown strong leadership in creating and implementing policies and programs that reduce GHG emissions from the power sector while achieving other economic, environmental, and energy benefits. Some of these activities, such as market-based programs and GHG performance standards, directly require GHG emission reductions from EGUs. Others reduce GHG emissions by reducing utilization of fossil fuel-fired EGUs through, for example, renewable portfolio standards (RPS) and energy efficiency resource standards (EERS), which alter the mix of energy supply and reduce energy demand. States have developed their policies and programs with stakeholder input and tailored them to their own circumstances and priorities. Their leadership and experiences provided the EPA with important information about best practices to build upon in this proposed rule. As directed by the Presidential Memorandum, the EPA is, with this proposal to reduce power plant carbon pollution, building on actions already underway in states and the power sector.

1. Market-Based Emission Limits

Nine states actively participate in the Regional Greenhouse Gas Initiative (RGGI), a market-based CO_2 emission reduction program addressing EGUs that was established in 2009.[47] Through RGGI, the participating states are implementing coordinated CO_2 emission budget trading programs. In aggregate, these programs establish an overall limit on allowable CO_2 emissions from affected EGUs in the participating states. Participating states issue CO_2 allowances in an amount up to the number of allowances in each state's annual emission budget. At the end of each three-year compliance period, affected EGUs must submit CO_2 allowances equal to their reported CO_2 emissions. CO_2 allowances may be traded among both regulated and non-regulated parties, creating a market for emission allowances. This market creates a price signal for CO_2 emissions, which factors into the dispatch of affected EGUs. A price signal for CO_2 emissions also allows sources flexibility to make emission reductions where reduction costs are lowest, and encourages innovation in developing emission control strategies.

Approximately 90 percent of CO_2 allowances are distributed by the RGGI participating states through auction.[48] From 2009 through 2012, the nine RGGI states invested auction proceeds of more than $700 million in programs that lower costs for energy consumers and reduce CO_2 emissions.[49] Through 2012, for example, the RGGI states invested approximately $460 million of proceeds into energy efficiency programs.[50] The participating RGGI states estimate that those investments are providing benefits to energy consumers in the region of more than $1.8 billion in lifetime energy savings.[51]

Between 2005, when an agreement to implement RGGI was announced, and 2012, power sector CO_2 emissions in the RGGI participating states fell by more than 40 percent.[52] RGGI was not the primary driver for these reductions but the reductions led RGGI-participating states to later adjust the CO_2 emission limits downward.[53] In January 2014, the participating states lowered the overall allowable CO_2 emission level in 2014 by 45 percent, setting a multi-state CO_2 emission limit for affected EGUs of 91 million short tons of CO_2 in 2014 and 78 million short tons of CO_2 in 2020, more than 50 percent below 2008 levels.[54]

Similarly, California established an economy-wide market-based GHG emissions trading program under the authority of its 2006 Global Warming Solutions Act, which requires the state to reduce its 2020 GHG emissions to 1990 levels.[55] While California's emission trading program, like its state emission limit, is multi-sector in scope, the state projects that the emissions trading program and related complementary measures will reduce power sector GHG emissions to less than 80 million metric tons of CO_2 equivalent by 2025, a 25 percent reduction from 2005 power sector emission levels.[56] Prior to the implementation of the emission trading program, California reports that it reduced CO_2 power sector emissions by 16 percent from 2005 to a 2010–2012

[47] The nine states include Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont.

[48] Regional Greenhouse Gas Initiative 2013 Allowance Allocation *http://rggi.org/design/overview/allowance-allocation/2013-allocation.*

[49] Regional Investments of RGGI CO_2 Allowance Proceeds, 2012 (2014), available at *http://www.rggi.org/docs/Documents/2012-Investment-Report.pdf.*

[50] Of the $707 million in auction proceeds invested by RGGI participating states through 2012, 65 percent supported end-use energy efficiency programs. See Regional Greenhouse Gas Initiative, ''Regional Investments of RGGI CO_2 Allowance Proceeds, 2012'' (2014). Available at *http://www.rggi.org/docs/Documents/2012-Investment-Report.pdf.*

[51] Id.

[52] Regional Greenhouse Gas Initiative, Report on Emission Reduction Efforts of the States Participating in the Regional Greenhouse Gas Initiative and Recommendations for Guidelines under Section 111(d) of the Clean Air Act (2013).

[53] The first three-year control period under RGGI, establishing CO_2 emission limits for EGUs, began on January 1, 2009.

[54] RGGI Press Release, January 13, 2014, *http://www.rggi.org/docs/PressReleases/PR011314_AuctionNotice23.pdf.*

[55] State of California Global Warming Solutions Act of 2006, Assembly Bill 32, Chapter *http://www.leginfo.ca.gov/pub/05-06/bill/asm/ab_0001-0050/ab_32_bill_20060927_chaptered.pdf.*

[56] Preliminary California Air Resources Board analyses, based in part on CARB 2008 to 2012 Emissions for Mandatory GHG reporting Summary (2013), cited in Letter to the EPA Administrator, ''States' Roadmap on Reducing Carbon Pollution,'' December 16, 2013. Available at *http://www.georgetownclimate.org/sites/default/files/EPA_Submission_from_States-FinalCompl.pdf.*

averaging period, a reduction of 16 million metric tons of CO_2 equivalent.[57]

2. GHG Performance Standards

Four states, California, New York, Oregon and Washington, have enacted GHG emission standards that impose enforceable emission limits on new and/or expanded electric generating units. For example, since 2012, New York requires new or expanded baseload plants that are greater than 25 Megawatts (MW) to meet an emission rate of either 925 pounds CO_2/Megawatt hour (MWh) (based on output) or 120 pounds of CO_2/Million British Thermal Units (MMBtu) (based on input). Similarly, non-baseload plants in New York of at least 25 MW or larger must meet an emission rate of either 1450 pounds CO_2/MWh (based on output) or 160 pounds of CO_2/MMBtu (based on input).[58]

Three states, California, Oregon and Washington, have enacted GHG emission performance standards that set an emission rate for electricity purchased by electric utilities. In both Oregon and Washington, for example, electric utilities may enter into long term power purchase agreements for baseload power only if the electric generator supplying the power has a CO_2 emission rate of 1,100 pounds of CO_2 per MWh or less.[59]

3. Utility Planning Approaches

Two states, Minnesota and Colorado, have worked collaboratively with their investor-owned utilities to develop multi-pollutant emission reduction plans on a utility-wide basis. This multi-pollutant, collaborative approach enables utilities to determine the least cost way to meet long term and comprehensive energy and environmental goals.

Colorado's Clean Air, Clean Jobs Act of 2010, for example, required Colorado investor-owned utilities with coal plants to develop a multi-pollutant plan to meet existing and reasonably foreseeable federal CAA requirements.[60] The utilities were not required to adopt a specific plan set by the state but were, instead, required to work collaboratively with the Colorado Department of Public Health and Environmental and Colorado Public Utility Commission to develop an acceptable plan. Xcel Energy, Colorado's largest investor-owned utility, submitted a plan that was approved in 2010. With this plan, Xcel Energy is projected to reduce its CO_2 emissions from generation in Colorado by 28 percent by 2020.[61]

4. Renewable Portfolio Standards

More than 25 states have mandatory renewable portfolio standards that require retail electricity suppliers to supply a minimum percentage or amount of their retail electricity load with electricity generated from eligible sources of renewable energy.[62] These standards have been established via utility regulatory commissions, legislatures and citizen ballots and requirements vary from state to state. State RPS typically specify the types of renewable energy, or other energy sources, that qualify for use toward achievement of the standard, and often allow for the use of qualifying renewable energy resources located outside of the state. They reduce utilization of fossil fuel-fired EGUs and, thereby, lead to reductions in GHG emissions by meeting a portion of the demand for electricity through renewable or other energy sources.

In 2007, the Minnesota legislature amended the state's 2001 renewable energy objective and established a renewable energy standard (RES) requiring at least 25 percent of all electricity generated or purchased in Minnesota to come from renewable energy by 2025. The standard sets requirements and timetables, beginning in 2010, that vary based on the provider. For example, in 2011, Xcel Energy had a requirement to generate or purchase 15 percent of its total retail sales from renewable energy while all other utilities had a target of 7 percent of total retail sales. According to the latest Minnesota Department of Commerce report to the legislature on progress, all utilities subject to the standard met it for 2011 and were on track to meet their 2012 goals.[63] The 2012 requirement increased to 18 percent of total retail sales for Xcel Energy and 12 percent for all other utilities.[64] In 2013, the Minnesota legislature expanded the RES with solar incentives and a specific solar energy standard requiring Minnesota utilities to ensure that at least 1.5 percent of their retail electricity sales in 2020 come from solar energy.[65]

The Oregon Renewable Portfolio Standard (RPS) is another example of a state requirement for renewables. Originally enacted in 2007, it requires that all utilities serving Oregon meet a percentage of their retail electricity needs with qualified renewable resources. Like in Minnesota, the percentage varies across utilities with the three largest utilities required to reach five percent from renewable energy sources starting in 2011, 15 percent in 2015, 20 percent in 2020, and 25 percent in 2025. Other electric utilities in the state are required to reach levels of five percent or ten percent by 2025, depending on their size. According to the latest RPS compliance reports submitted by the largest utilities for the state, each had achieved the five percent target as of the end of 2012.[66]

5. Demand-Side Energy Efficiency Programs

Many electric utilities, third-party administrators, and states implement demand-side energy efficiency programs to reduce generation from EGUs by reducing electricity use, including peak demand. When these programs reduce fossil fuel electricity generation, they also reduce CO_2 emissions. Demand-side energy efficiency programs use a variety of energy efficiency measures to target a variety of end uses and are often driven by existing state standards and programs, such as policies requiring utilities to obtain ''all cost-effective energy efficiency'' through long-term integrated resource planning (IRP), renewable portfolio standards (RPS) that include efficiency as a qualifying resource, energy efficiency resource standards (EERS), public benefit funds, and other demand-side planning requirements.

The purposes of demand-side energy efficiency programs vary; goals include to reduce GHG emissions by reducing fossil-fired generation, help states achieve energy savings goals, save energy and money for consumers and improve electricity reliability. They are typically funded through a small fee or surcharge on customer electricity bills, but can also be funded by other sources, such as from RGGI CO_2 allowance auction proceeds mentioned above.

[57] Id.

[58] 6 New York Codes, Rules & Regulations. Part 251 (Adopted June 28, 2012).

[59] OR SB 101 (2000); Washington Revised Code ch.80.80 (2013); Wash SB 6001 (2007).

[60] Colorado Clean Air, Clean Jobs Act, HB1365.

[61] Xcel Energy, Colorado Clean Air-Clean Jobs Plan, available at *http://www.xcelenergy.com/Environment/Doing_Our_Part/Clean_Air_Projects/Colorado_Clean_Air_Clean_Jobs_Plan.*

[62] *http://www.dsireusa.org/.*

[63] Report to the Minnesota Legislature: Progress on Compliance By Electric Utilities With The Minnesota Renewable Energy Objective and the Renewable Energy Standard, Prepared by: The Minnesota Department of Commerce, Division of Energy Resources January 14, 2013; *http://mn.gov/commerce/energy/images/2013RESLegReport.pdf.*

[64] Id.

[65] Minnesota Statutes 2013, Section 216B.1691, Subdivision 2f. Solar Energy Standard *https://www.revisor.mn.gov/statutes/?id=216b.1691.*

[66] Eugene Water Electric Board Oregon Renewable Portfolio Standard 2012 Compliance Report and 2013–2030 Implementation Plan, June 1, 2013. PacifiCorp's Renewable Portfolio Standard Oregon Compliance Report for 2012, May 31, 2013. PGE 2012 Renewable Portfolio Standard Compliance Report, June 1, 2013.

Nationally, total spending on electric ratepayer-funded energy efficiency programs was about $5 billion in 2012.[67] Based on Lawrence Berkeley National Laboratory (LBNL) projections, spending is projected to reach $8.1 billion in 2025.[68]

Electricity savings from energy efficiency programs are also growing. In 2011, electricity savings from these programs totaled approximately 22.9 million MWh, a 22 percent increase from the previous year.[69]

California has been advancing energy efficiency through utility-run demand-side energy efficiency programs for decades and considers energy efficiency ''the bedrock upon which climate policies are built.'' [70] It requires its investor-owned utilities to meet electricity load ''through all available energy efficiency and demand reduction resources that are cost-effective, reliable and feasible.'' [71] The California Public Utility Commission works with the California Energy Commission to determine the amount of cost-effective reduction potential and establishes efficiency targets. A recent energy efficiency potential study found that, even after years of running programs, California can still tap ''tens of thousands of GWh in potential savings . . . over the next decade.'' [72] Investor-owned utilities use demand-side energy efficiency programs to achieve their targets and currently ''save about 3,000 GW per year, enough savings to power about 600,000 households.'' [73] Between 2010 and 2011, these programs are estimated to have reduced CO_2 by 3.8 million tons.[74]

In Vermont, for example, the Vermont Legislature and the Vermont Public Service Board (PSB) established the first statewide ''energy efficiency utility'' in 1999 to provide energy efficiency services to residences and businesses throughout the state.[75] Vermont law requires that the energy efficiency utility budgets be set at a level to achieve ''all reasonably available, cost-effective energy efficiency'' and then specific energy (kWh) and peak demand (kW) savings levels are negotiated every three years.[76] In 2013, Efficiency Vermont, the PSB-appointed energy efficiency utility, achieved annual savings of 1.66 percent of the state's electricity sales, at a cost of 4.1 cents per kilowatt-hour, lower than the cost of comparable electric supply in the same year, which was 8.4 cents per kWh.[77] Efficiency Vermont projects a net lifetime economic value to Vermont of more than $60 million from the 2013 energy efficiency investments.[78]

6. Energy Efficiency Resource Standards

More than 20 states have energy efficiency resource standards (EERS) that require utilities to save a certain amount of energy each year or cumulatively.[79] They are typically multi-year requirements expressed as a percentage of annual retail electricity sales or as specific electricity savings amounts over a long term period relative to a baseline of retail sales. Over the compliance period, an EERS reduces fossil fuel-fired EGU generation through reductions in electricity demand, thereby reducing CO_2 emissions from the power sector.

In Arizona, for example, the Arizona Corporation Commission (ACC) adopted rules in 2010 requiring all investor-owned utilities to achieve 22 percent cumulative electricity savings by 2020, making it one of the highest standards in the nation.[80] The rule required utilities to achieve 1.25 percent electricity savings in 2011 compared to electricity sales in the previous year, ramping up the savings each year until 2020 according to a designated timetable.[81] In 2012, for example, investor-owned utilities were required to achieve energy savings equivalent to 1.75 percent of the 2011 sales, leading to a cumulative savings requirement of 3 percent by the end of 2012 (an average of 1.5% annually over the 2 year period).[82] Utilities can meet the energy savings requirements through a variety of means, including cost-effective energy efficiency programs, as well as load management and demand response programs.[83] Arizona Public Service Company (APS), the largest utility in Arizona, achieved cumulative energy savings equivalent to 3.2 percent of retail sales from 2011 to 2012, exceeding the 3 percent savings target, and reported a net benefit to consumers of more than $200 million for the year 2012 alone.[84]

E. Conclusions

States have taken a leadership role in mitigating GHG emissions and have demonstrated the potential for national application of a number of approaches. Throughout the development of this proposed rule, the EPA considered the states' experiences and lessons learned regarding the design and implementation of successful GHG mitigation programs. The agency also fully considered input from stakeholders during the development of this proposed rulemaking.

Considering all input from stakeholders, the agency recognizes that the most cost-effective approach to reducing GHG emissions from the power sector under CAA section 111(d) is to follow the lead of numerous states and not only to identify improvements in the efficiency of fossil fuel-fired EGUs as a component of the BSER, but also include in the BSER determination the EGU-emissions-reduction opportunities that states have already demonstrated to be successful in relying on lower- and zero-emitting generation and reduced electricity demand.

CAA section 111(d) sets up a partnership between the EPA and the states. In the context of that partnership, the EPA recognizes the importance of each state having the flexibility to design a cost-effective program tailored to its own specific circumstances. The agency also recognizes, as many states

[67] Consortium for Energy Efficiency Annual Industry Report: 2013 State of the Efficiency Program Industry—Budgets, Expenditures and Impacts, 2014.

[68] Lawrence Berkeley National Laboratory (LBNL) The Future of Utility Customer-Funded Energy Efficiency Programs in the United States: Projected Spending and Savings to 2025 (*http://emp.lbl.gov/sites/all/files/lbnl-5803e.pdf*).

[69] American Council for an Energy Efficient Economy (ACEEE) 2013 State Scorecard *http://www.aceee.org/sites/default/files/publications/researchreports/e13k.pdf.*

[70] December 27, 2013 Letter from Mary D. Nichols, Chairman of California Air Resources Board, to EPA Administrator Gina McCarthy.

[71] Cal Pub. Utility Code § 454.5 (a)(9)(C).

[72] Cited in December 27, 2013 Letter from Mary D. Nichols, Chairman of California Air Resources Board, to EPA Administrator Gina McCarthy.

[73] Id.

[74] Id.

[75] State of Vermont Public Service Board, Energy Efficiency Utility Creation and Structure. *http://psb.vermont.gov/utilityindustries/eeu/generalinfo/creationandstructure*.

[76] Vermont Statute, Title 30: Public Service, 30 V.S.A. § 209 (d)3(B). *http://www.leg.state.vt.us/statutes/fullsection.cfm?Title=30&Chapter=005&Section=00209.*

[77] Efficiency Vermont Savings Claim Summary 2013, Reported to the Vermont Public Service Board and to the Vermont Public Service Department, 2014, *https://www.efficiencyvermont.com/docs/about_efficiency_vermont/annual_summaries/2013_savingsclaim_summary.pdf.*

[78] Id.

[79] State Energy Efficiency Resource Standards: Policy Design, Status, and Impacts, DC Steinberg, O. Zinaman, NREL Technical Report NREL/TP–6A20–61023, April 2014.

[80] Arizona Corporation Commission, Docket RE–OOOOOC–09–0427, August 2010. Available at *http://images.edocket.azcc.gov/docketpdf/0000116125.pdf.*

[81] Id.

[82] Arizona Corporation Commission, Docket RE–OOOOOC–09–0427, August 2010. Available at *http://images.edocket.azcc.gov/docketpdf/0000116125.pdf.*

[83] Id.

[84] Arizona Public Service Company 2012 Demand Side Management Annual Progress Report, March 1, 2013 Web site, *http://www.aps.com/en/ourcompany/aboutus/energyefficiency/Pages/home.aspx.*

have, the value of regional planning in designing approaches to achieve cost-effective GHG reductions. To support state flexibility and encourage multi-state coordination in the development of multi-state and regional programs and policies, the EPA recognizes that flexibility in both the timing of plan submittal and the timing of CO_2 emission reductions will be necessary.

IV. Rule Requirements and Legal Basis

A. Summary of Rule Requirements

The EPA is proposing emission guidelines for each state to use in developing plans to address greenhouse gas emissions from existing fossil fuel-fired electric generating units. The emission guidelines are based on the EPA's determination of the ''best system of emission reduction . . . adequately demonstrated'' (BSER) and include state-specific goals, general approvability criteria for state plans, requirements for state plan components, and requirements for the process and timing for state plan submittal and compliance.

Under CAA section 111(d), the states must establish standards of performance that reflect the degree of emission limitation achievable through the application of the ''best system of emission reduction'' that, taking into account the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirements, the Administrator determines has been adequately demonstrated. Consistent with CAA section 111(d), the EPA is proposing state-specific goals that reflect the EPA's calculation of the BSER.

Under CAA section 111(d), each state must develop, adopt, and then submit its plan to the EPA. To do so, the state would determine, and include in its plan, an emission performance level that is equivalent to the state-specific CO_2 goal in the emission guidelines. As part of determining this level, the state would decide whether to adopt the rate-based form of the goal established by the EPA or translate the rate-based goal to a mass-based goal. The state would then establish a standard of performance or set of standards of performance (known as emission standards under the existing CAA section 111(d) framework regulations), along with implementing and enforcing measures, that will achieve a level of emission performance that equals or exceeds the level specified in the state plan.

The EPA is proposing to determine the BSER as the combination of emission rate improvements and limitations on overall emissions at affected EGUs that can be accomplished through any combination of one or more measures from the following four sets of measures or building blocks:

1. Reducing the carbon intensity of generation at individual affected EGUs through heat rate improvements.

2. Reducing emissions from the most carbon-intensive affected EGUs in the amount that results from substituting generation at those EGUs with generation from less carbon-intensive affected EGUs (including natural gas combined cycle (NGCC) units that are under construction).

3. Reducing emissions from affected EGUs in the amount that results from substituting generation at those EGUs with expanded low- or zero-carbon generation.

4. Reducing emissions from affected EGUs in the amount that results from the use of demand-side energy efficiency that reduces the amount of generation required.

The EPA has reviewed information about the current and recent performance of affected EGUs and states' implementation of programs that reduce CO_2 emissions from these sources. Based on our analysis of that information, the proposed state goals reflect the following stringency of application of the measures in each of the building blocks: Block 1, improving average heat rate of coal-fired steam EGUs by six percent; block 2, displacing coal-fired steam and oil/gas-fired steam generation in each state by increasing generation from existing NGCC capacity in that state toward a 70 percent target utilization rate; block 3, including the projected amounts of generation achievable by completing all nuclear units currently under construction, avoiding retirement of about six percent of existing nuclear capacity, and increasing renewable electric generating capacity over time through the use of state-level renewable generation targets consistent with renewable generation portfolio standards that have been established by states in the same region; and block 4, increasing state demand-side energy efficiency efforts to reach 1.5 percent annual electricity savings in the 2020–2029 period.

Based on the EPA's application of the BSER to each state, the EPA is proposing to establish, as part of the emission guidelines, state-specific goals, expressed as average emission rates for fossil fuel-fired EGUs. Each state's goals comprise the EPA's determination of the emission limitation achievable through application of the BSER in that state. For each state, the EPA is proposing an interim goal for the phase-in period from 2020 to 2029 and the final goal that applies beginning in 2030. The proposed goals for each state are listed in Section VII, below. The EPA is proposing that measures that a state takes after the date of this proposal, and that result in CO_2 emission reductions during the plan period, would apply toward achievement of the state's CO_2 goal.

The EPA is further proposing, as part of the plan guidelines, timetables for states to submit their plans. The agency expects to finalize this rulemaking by June 2015, and we are proposing to require that each state submit its plan to the EPA by June 30, 2016. However, if a state needs additional time to submit a complete plan, the state must submit an initial plan by June 30, 2016, that documents the reasons why more time is needed to submit a complete plan and includes commitments to take concrete steps that will ensure that the state will submit a complete plan by June 30, 2017, or June 30, 2018, as appropriate. If such a state is developing a plan limited in geographical scope to the individual state, then the state would have until June 30, 2017, to submit a complete plan. A state that is developing a plan that includes a multi-state approach would have until June 30, 2018, to submit a complete plan.

The EPA is further proposing, as part of the emission guidelines, to allow states the option of translating the EPA-determined goal, which will be rate-based, to a mass-based goal. For states participating in a multi-state approach, the individual state performance goals in the emission guidelines would be replaced with an equivalent multi-state performance goal. The EPA is also proposing that in their plans, whether single state or multi-state, states may not adjust the stringency of the goals set by the EPA.

Under CAA section 111(d)(1) and the implementing regulations, with the state emission performance level in place, the state must adopt a state plan that establishes a standard of performance or set of standards of performance, along with implementing and enforcing measures, that will achieve that emission performance level. The EPA is further proposing, as part of the guidelines, to authorize the state to submit either of two types of measures to achieve the performance level: (1) A set of measures that we refer to as ''portfolio'' measures, which include a combination of emission limitations that apply directly to the affected sources and other measures that have the effect of limiting generation by, and therefore emissions from, the affected sources; or (2) solely emission limitations that apply directly to the affected sources.

The EPA is also proposing, as part of the plan guidelines, that a complete state plan include the following twelve components:

- Identification of affected entities
- Description of plan approach and geographic scope
- Identification of state emission performance level
- Demonstration that plan is projected to achieve emission performance level
- Identification of emissions standards
- Demonstration that each emissions standard is quantifiable, non-duplicative, permanent, verifiable, and enforceable
- Identification of monitoring, reporting, and recordkeeping requirements
- Description of state reporting
- Identification of milestones
- Identification of backstop measures
- Certification of hearing on state plan
- Supporting material

The EPA is also proposing, as part of its emission guidelines, that plan approvability be based on four general criteria: (1) Enforceable measures that reduce EGU CO_2 emissions; (2) projected achievement of emission performance equivalent to the goals established by the EPA, on a timeline equivalent to that in the emission guidelines; (3) quantifiable and verifiable emission reductions; and (4) a process for reporting on plan implementation, progress toward achieving CO_2 goals, and implementation of corrective actions, if necessary.

The EPA is also proposing, as part of its plan guidelines, requirements for the process and timing for demonstrating achievement of the required emission performance level, including performance and emission milestones. The proposed option would require each state to achieve its ultimate CO_2 emission performance level by 2030 and, in addition, provide an initial, phase-in compliance period of up to 10 years, from 2020 up to 2029, for a state and/or other responsible parties to comply with the emission performance level in the state plan. A state would need to meet its interim 2020–2029 CO_2 emission performance level on average over the 10-year phase-in compliance period, achieve its final CO_2 emission performance level by 2030, and maintain it thereafter.

If a state with affected EGUs does not submit a plan or if the EPA does not approve a state's plan, then under CAA section 111(d)(2)(A), the EPA must establish a plan for that state. A state that has no affected EGUs must document this in a formal letter submitted to the EPA by June 30, 2016. In the case of a tribe that has one or more affected EGUs in its area of Indian country,[85] the tribe would have the opportunity, but not the obligation, to establish a CO_2 emission performance standard and a CAA section 111(d) plan for its area of Indian country. If it determines that such a plan is necessary or appropriate, the EPA has the responsibility to establish CAA section 111(d) plans for areas of Indian country where affected sources are located unless a tribe on whose lands an affected source (or sources) is located seeks and obtains authority from the EPA to establish a plan itself, pursuant to the Tribal Authority Rule.

B. Summary of Legal Basis

This proposed action is consistent with the requirements of CAA section 111(d) and the implementing regulations. As an initial matter, the EPA reasonably interprets the provisions identifying which air pollutants are covered under CAA section 111(d) to authorize the EPA to regulate CO_2 from fossil fuel-fired EGUs. In addition, the EPA recognizes that CAA section 111(d) applies to sources that, if they were new sources, would be covered under a CAA section 111(b) rule. The EPA intends to complete two CAA section 111(b) rulemakings regulating CO_2 from new fossil fuel-fired EGUs and from modified and reconstructed fossil fuel-fired EGUs before it finalizes this rulemaking, and either of those section 111(b) rulemakings will provide the requisite predicate for this rulemaking.

A key step in promulgating requirements under CAA section 111(d) is determining the ''best system of emission reduction . . . adequately demonstrated'' (BSER). In promulgating the implementing regulations, the EPA explicitly stated that it is authorized to determine the BSER;[86] accordingly, in this rulemaking, the EPA is determining the BSER.

The EPA is proposing two alternative BSER for fossil fuel-fired EGUs, each of which is based on methods that have already been employed for reducing emissions of air pollutants, including, in some cases, CO_2, from these sources. The first identifies the combination of the four building blocks as the BSER. These include operational improvements and equipment upgrades that the coal-fired steam-generating EGUs in the state may undertake to improve their heat rate (building block 1) and increases in, or retention of, zero- or low-emitting generation, as well as measures to reduce demand for generation, all of which, taken together, displace, or avoid the need for, generation from the affected EGUs (building blocks 2, 3, and 4). All of these measures are components of a ''system of emission reduction'' for the affected EGUs because they either improve the carbon intensity of the affected EGUs in generating electricity or, because of the integrated nature of the electricity system and the fungibility of electricity, they displace or avoid the need for generation from those sources and thereby reduce the emissions from those sources. Moreover, those measures may be undertaken by the affected EGUs themselves and, in the case of building blocks 2, 3, and 4, they may be required by the states.

Further, these measures meet the criteria in CAA section 111(a)(1) and the caselaw as the ''best'' system of emission reduction because, among other things, they achieve the appropriate level of reductions, they are of reasonable cost, and they encourage technological development that is important to achieving further emission reductions. Moreover, the measures in each of the building blocks are ''adequately demonstrated'' because they are each well-established in numerous states, and many of them have already been relied on to reduce GHGs and other air pollutants from fossil fuel-fired EGUs. It should be emphasized that these measures are consistent with current trends in the electricity sector.

For the alternative approach for the BSER, the EPA is identifying the ''system of emission reduction'' as including, in addition to building block 1, the reduction of affected fossil fuel-fired EGUs' mass emissions achievable through reductions in generation of specified amounts from those EGUs. Under this approach, the measures in building blocks 2, 3, and 4 would not be components of the system of emission reduction, but instead would serve as bases for quantifying the reduction in emissions resulting from the reduction in generation at affected EGUs. In light of the available sources of replacement generation through the measures in the building blocks, this approach would also meet the criteria for being the ''best'' system that is ''adequately demonstrated'' because of the emission reductions it would

[85] The EPA is aware of at least four affected EGUs located in Indian country: Two on Navajo lands, the Navajo Generating Station and the Four Corners Generating Station; one on Ute lands, the Bonanza Generating Station; and one on Fort Mojave lands, the South Point Energy Center. The affected EGUs at the first three plants are coal-fired EGUs. The fourth affected EGU is an NGCC facility.

[86] The EPA is not re-opening that interpretation in this rulemaking.

achieve, its reasonable cost, and its promotion of technological development, as well as the fact that the reliability of the electricity system would be maintained.

After determining the BSER, the EPA is authorized under the implementing regulations, as an integral component to setting emission guidelines, to apply the BSER and determine the resulting emission limitation. The EPA is proposing to apply the BSER to the affected EGUs on a statewide basis. In this rulemaking, the EPA terms the resulting emission limitation the state goal.

With the promulgation of the emission guidelines, each state must develop a plan to achieve an emission performance level that corresponds to the state goal. The state plans must establish standards of performance for the affected EGUs and include measures that implement and enforce those standards. Based on requests from stakeholders, the EPA is proposing that states be authorized to submit state plans that do not impose legal responsibility on the affected EGUs for the entirety of the emission performance level, but instead, by adopting what this preamble refers to as a ''portfolio approach,'' impose requirements on other affected entities (e.g., renewable energy and demand-side energy efficiency measures) that would reduce CO_2 emissions from the affected EGUs.

It should be noted that an important aspect of the BSER for affected EGUs is that the EPA is proposing to apply it on a statewide basis. The statewide approach also underlies the required emission performance level, which, as noted, is based on the application of the BSER to a state's affected EGUs, and which the suite of measures in the state plan, including the emission standards for the affected EGUs, must achieve overall. The state has flexibility in assigning the emission performance obligations to its affected EGUs, in the form of standards of performance—and, for the portfolio approach, in imposing requirements on other entities—as long as, again, the required emission performance level is met.

This state-wide approach both harnesses the efficiencies of emission reduction opportunities in the interconnected electricity system and is fully consistent with the principles of federalism that underlie the Clean Air Act generally and CAA section 111(d) particularly. That is, this provision achieves the emission performance requirements through the vehicle of a state plan, and provides each state significant flexibility to take local circumstances and state policy goals into account in determining how to reduce emissions from its affected sources, as long as the plan meets minimum federal requirements. This state-wide approach, and the standards of performance for the affected EGUs that the states will establish through the state-plan process, are consistent with the applicable CAA section 111 provisions.

A state has discretion in determining the measures in its plans. The state may adopt measures that assure the achievement of the required emission performance level, and is not limited to the measures that the EPA identifies as part of the BSER. By the same token, the affected EGUs, to comply with the applicable standards of performance in the state plan, may rely on any efficacious means of emission reduction, regardless of whether the EPA identifies those measures as part of the BSER.

In this rulemaking, the EPA proposes reasonable deadlines for state plan submission and the EPA's action. The proposed deadline for the EPA's action on state plan submittals varies from that in the implementing regulations, and the EPA is proposing to revise that provision in the regulations accordingly. Under CAA section 111(d)(2), the state plans must be ''satisfactory'' for the EPA to approve them, and in this rulemaking, the EPA is proposing the criteria that the state plans must meet under that requirement.

The EPA discusses its legal interpretation in more detail in other parts of this preamble and discusses certain issues in more detail in the Legal Memorandum included in the docket for this rulemaking. The EPA solicits comment on all aspects of its legal interpretations, including the discussion in the Legal Memorandum.

V. Authority To Regulate Carbon Dioxide and EGUs, Affected Sources, Treatment of Categories

A. Authority To Regulate Carbon Dioxide

The EPA has the authority to regulate, under CAA section 111(d), CO_2 emissions from EGUs, under the Agency's construction of the ambiguous provisions in CAA section 111(d)(1)(A)(i) that identify the air pollutants subject to CAA section 111(d). The ambiguities stem from apparent drafting errors that occurred during enactment of the 1990 CAA Amendments, which revised section 111(d).

During the 1990 CAA Amendments, the House of Representatives and the Senate each passed an amendment to CAA section 111(d)(1)(A)(i). The two amendments differed from each other, and were not reconciled during the Conference Committee and, as a result, both were enacted into law. As amended by the Senate, the pertinent language of CAA section 111(d)(1) would exclude the regulation of any pollutant which is ''included on a list published under [CAA section] 112(b).''[87] As amended by the House, the pertinent language in CAA section 111(d)(1) would exclude the regulation of any pollutant which is ''emitted from a source category which is regulated under section 112.''[88] The two versions conflict with each other and thus are ambiguous. Under these circumstances, the EPA may reasonably construe the provision to authorize the regulation of GHGs under CAA section 111(d).

It should be noted that the U.S. Supreme Court's holding in *American Electric Power Co.* v. *Connecticut,* 131 S. Ct. 2527, 2537–38 (2011), that ''the Clean Air Act and the EPA actions it authorizes displace any federal common law right to seek abatement of carbon-dioxide emissions from fossil fuel-fired power plants'' was premised on the Court's understanding that CAA section 111, including CAA section 111(d), applies to carbon dioxide emissions from those sources.

We discuss this issue in more detail in the Legal Memorandum.

B. Authority To Regulate EGUs

Before the EPA finalizes this CAA section 111(d) rule, the EPA will finalize a CAA section 111(b) rulemaking regulating CO_2 emissions from new EGUs, which will provide the requisite predicate for applicability of CAA section 111(d).

CAA section 111(d)(1) requires the EPA to promulgate regulations under which states must submit state plans regulating ''any existing source'' of certain pollutants ''to which a standard of performance would apply if such existing source were a new source.'' A ''new source'' is ''any stationary source, the construction or modification of which is commenced after the publication of regulations (or, if earlier, proposed regulations) prescribing a standard of performance under [CAA section 111] which will be applicable to such source.'' It should be noted that these provisions make clear that a ''new source'' includes one that undertakes either new construction or a modification. It should also be noted

[87] Public Law 101–549, § 302(a), 104 Stat. at 2574 (Nov. 15, 1990).

[88] Public Law 101–549, § 108(g), 104 Stat. at 2467 (Nov. 15, 1990).

that the EPA's implementing regulations define ''construction'' to include ''reconstruction,'' which the implementing regulations go on to define as the replacement of components of an existing facility to an extent that (i) 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 (ii) it is technologically and economically feasible to meet the applicable standards.

Under CAA section 111(d)(1), in order for existing sources to become subject to that provision, the EPA must promulgate standards of performance under CAA section 111(b) to which, if the existing sources were new sources, they would be subject. Those standards of performance may include ones for sources that undertake new construction, modifications, or reconstructions.

The EPA is in the process of promulgating two rulemakings under CAA section 111(b) for CO_2 emissions from affected sources. The EPA proposed the first, which applies to affected sources undertaking new constructions, by notice dated January 8, 2014, which we refer to as the January 2014 Proposal. The EPA is proposing the second, which applies to affected sources undertaking modifications or reconstructions, concurrently with this CAA section 111(d) proposal. The EPA will complete one or both of these CAA section 111(b) rulemakings before or concurrently with this CAA section 111(d) rulemaking, which will provide the requisite predicate for applicability of CAA section 111(d).[89]

C. Affected Sources

The EPA is proposing that, for the emission guidelines, an affected EGU is any fossil fuel-fired EGU that was in operation or had commenced construction as of January 8, 2014, and is therefore an ''existing source'' for purposes of CAA section 111, and that in all other respects would meet the applicability criteria for coverage under the proposed GHG standards for new fossil fuel-fired EGUs (79 FR 1430; January 8, 2014).

The January 8, 2014 proposed GHG standards for new EGUs generally define an affected EGU as any boiler, integrated gasification combined cycle (IGCC), or combustion turbine (in either simple cycle or combined cycle configuration) that (1) is capable of combusting at least 250 million Btu per hour; (2) combusts fossil fuel for more than 10 percent of its total annual heat input (stationary combustion turbines have an additional criteria that they combust over 90 percent natural gas); (3) sells the greater of 219,000 MWh per year and one-third of its potential electrical output to a utility distribution system; and (4) was not in operation or under construction as of January 8, 2014 (the date the proposed GHG standards of performance for new EGUs were published in the **Federal Register**). The minimum fossil fuel consumption condition applies over any consecutive three-year period (or as long as the unit has been in operation, if less). The minimum electricity sales condition applies on an annual basis for boilers and IGCC facilities and over rolling three-year periods for combustion turbines (or as long as the unit has been in operation, if less).

The rationale for this proposal concerning applicability is the same as that for the January 8, 2014 proposal, sections V.A–B. See 79 FR at 1,459/1–1,461/2. We incorporate that discussion by reference here.

D. Implications for Tribes and U.S. Territories

As noted in Section II.D of this preamble, although affected EGUs located in Indian country operate as part of the interconnected system of electricity production and distribution, affected EGUs located in Indian country within a state's borders would not be encompassed within the state's CAA section 111(d) plan. The EPA is aware of four potentially affected power plants located in Indian country: The South Point Energy Center, on Fort Mojave tribal lands within Arizona; the Navajo Generating Station, on Navajo tribal lands within Arizona; the Four Corners Power Plant, on Navajo tribal lands within New Mexico; and the Bonanza Power Plant, on Ute tribal lands within Utah. The South Point facility is an NGCC power plant, and the Navajo, Four Corners, and Bonanza facilities are coal-fired power plants. The operators and co-owners of these four facilities include investor-owned utilities, cooperative utilities, public power agencies, and independent power producers, most of which also co-own potentially affected EGUs within state jurisdictions. We are not aware of any potentially affected EGUs that are owned or operated by tribal entities. If it determines that such a plan is necessary or appropriate, the EPA has the responsibility to establish CAA section 111(d) plans for areas of Indian country where affected sources are located unless a tribe on whose lands an affected source (or sources) is located seeks and obtains authority from the EPA to establish a plan itself, pursuant to the Tribal Authority Rule.[90] The EPA intends to publish a supplemental proposal to establish emission performance goals (if it determines that such action is necessary or appropriate) covering the four potentially affected power plants identified above, as well as any subsequently identified similarly situated power plants, and also to proposed goals for U.S. territories with affected EGUs. The EPA intends to take final action on that proposal by June 2015. If a tribe does seek and obtain the necessary authority to establish a plan itself, it is the EPA's intention that the tribe would have flexibility to develop a plan tailored to its circumstances, in the same manner as a state, to meet CO_2 emission performance goals that would be established by the EPA based on application of the BSER to that area of Indian country. The EPA is aware of actions that have been taken or are being taken by some sources in tribal areas or territories and will be mindful of these actions in considering establishment of a plan.

The EPA invites comment on whether a tribe wishing to develop and implement a CAA section 111(d) plan should have the option of including the EGUs located in its area of Indian country in a multi-jurisdictional plan with one or more states (i.e., treating the tribal lands as an additional state).

If the EPA develops one or more CAA section 111(d) federal plans for areas of Indian country with affected EGUs, we are likewise currently considering doing so on a multi-jurisdictional basis in coordination with nearby states developing section 111(d) state plans. The EPA solicits comment on such an approach for a federal plan.

At this time, the EPA is not proposing CO_2 emission performance goals for areas of Indian country containing potentially affected EGUs. We do plan to establish such goals in the future, to be addressed through either tribal or federal plans, as discussed above. The EPA notes that some present and planned actions being taken to reduce criteria pollutants from EGUs in Indian country will result in significant CO_2 emission reductions relative to emissions in the 2012 baseline period used in computing the state CO_2

[89] In the past, the EPA has issued standards of performance under section 111(b) and emission guidelines under section 111(d) simultaneously. *See* ''Standards of Performance for new Stationary Sources and Guidelines for Control of Existing Sources: Municipal Solid Waste Landfills—Final Rule,'' 61 FR 9905 (March 12, 1996).

[90] See 40 CFR 49.1 to 49.11.

performance goals in this proposal.[91] We invite comment on how the BSER should be applied to potentially affected EGUs in Indian country. We particularly invite comment on data sources for setting renewable energy and demand-side energy efficiency targets.

The state-specific goals that the EPA is proposing are based on the collection of affected EGUs located within that state. In setting goals specific to an area of Indian country, the EPA proposes to base the goals on the collection of affected EGUs located within that area of Indian country. We request comment on this approach.

E. Combined Categories and Codification in the Code of Federal Regulations

In this rulemaking, the EPA is soliciting comment on combining the two existing categories for the affected EGUs into a single category for purposes of facilitating emission trading among sources in both categories. The EPA is also proposing codifying all of the proposed requirements for the affected EGUs in a new subpart UUUU of 40 CFR part 60.

As discussed in the January 8, 2014 proposal for the CAA section 111(b) standards for GHG emissions from EGUs, in 1971 the EPA listed fossil fuel-fired steam generating boilers as a new category subject to section 111 rulemaking, and in 1979 the EPA listed fossil fuel-fired combustion turbines as a new category subject to the CAA section 111 rulemaking. In the ensuing years, the EPA has promulgated standards of performance for the two categories, and codified those standards, at various times, in 40 CFR part 60 subparts D, Da, GG, and KKKK. In the 2014 proposal, the EPA proposed separate standards of performance for sources in the two categories and proposed codifying the standards in the same Da and KKKK subparts that currently contain the standards of performance for conventional pollutants from those sources. In addition, the EPA co-proposed combining the two categories into a single category solely for purposes of the CO_2 emissions from new construction of affected EGUs, and codifying the proposed requirements in a new 40 CFR part 60 subpart TTTT. The EPA solicited comment on whether combining the categories for new sources is necessary in order to combine the categories for existing sources.

In the present rulemaking, the EPA is proposing emission guidelines for the two categories and is soliciting comment on combining the two categories into a single category for purposes of the CO_2 emissions from existing affected EGUs. The EPA solicits comment on whether combining the two categories would offer additional flexibility, for example, by facilitating implementation of CO_2 mitigation measures, such as shifting generation from higher to lower-carbon intensity generation among existing sources (e.g., shifting from boilers to NGCC units) or facilitating emissions trading among sources. Because the two categories are pre-existing and the EPA would not be subjecting any additional sources to regulation, the combined category would not be considered a new category that the EPA must list under CAA section 111(b)(1)(A). As a result, this proposal does not list a new category under section 111(a)(1)(A), nor does this proposal revise either of the two source categories—steam-generating boilers and combustion turbines—that the EPA has already listed under that provision. Thus, the EPA would not be required to make a finding that the combined category causes or contributes significantly to air pollution which may reasonably be anticipated to endanger public health or welfare.

In addition, the EPA is proposing to create a new subpart UUUU and to include all GHG emission guidelines for the affected sources—utility boilers and IGCC units as well as natural gas-fired stationary combustion turbines—in that newly created subpart. We believe that combining the emission guidelines for affected sources into a new subpart UUUU is appropriate because the emission guidelines the EPA is establishing do not vary by type of source. Accordingly, the EPA is not proposing to codify any of the requirements of this rulemaking in subparts Da or KKKK.

VI. Building Blocks for Setting State Goals and the Best System of Emission Reduction

A. Introduction

Based on the experiences of states and the industry and the EPA's outreach with stakeholders as described above, the EPA has identified multiple measures currently in use for achieving CO_2 emission reductions from existing fossil fuel-fired EGUs. For purposes of determining the ''best system of emission reduction . . . adequately demonstrated'' (BSER) and developing state emission performance goals, we have screened the measures and have found that they support two alternative formulations for the BSER. We are grouping the measures that we are proposing to consider further at this time into four categories, which we call ''building blocks.'' We provide an overview of these building blocks in Section VI.B and more detailed discussion of each block in Section VI.C. In Section VI.D we discuss possible combinations of the building blocks, and in Section VI.E, we explain why as a legal matter all four building blocks, taken together, support the BSER, which in turn serves as the basis for the standards of performance that the states must include in their state plans, as CAA section 111(d) requires.

As discussed in Section III of this preamble, we are mindful of numerous and varied stakeholder concerns, including the need to achieve meaningful CO_2 emission reductions at the affected facilities and to recognize and take advantage of the progress already made by existing programs. Like stakeholders, we are attentive to the need to maintain electricity system reliability and to minimize adverse impacts on electricity and fuel prices and on assets that have already been improved by installation of controls for other kinds of pollution. Many of these considerations align with our approach to determining the BSER, as discussed more in Section VII, and we consider several of these to be key principles in this application. As discussed in Sections VII and VIII, we acknowledge and appreciate the advantages of allowing and promoting flexibility for states in crafting their programs. We recognize the knowledge that states have about their specific situations and their ability to evaluate and leverage existing and new capacity and programs to ultimately reduce EGU CO_2 emissions.

Similarly, we recognize and appreciate that states operate with differing circumstances and policy preferences. For example, states have differing access to specific fuel types, and the variety of types of EGUs operating in different states is broad and significant. States are part of assorted EGU dispatch systems and vary in the amounts of electricity that they import and export. For these reasons, we also recognize and appreciate the value in allowing and promoting multi-state reduction strategies. Some states already participate in a multi-state program that reduces CO_2 emissions, the RGGI, and we have noted the success of that program for those states.

[91] For example, a plan currently being implemented at the Four Corners plant to satisfy regional haze requirements calls for reduction of NOx emissions to be achieved in part by shutting down a portion of the plant's generating capacity, and a similar plan has been proposed for the Navajo plant. See 78 FR 62509 (October 22, 2013).

Another key consideration in determining the BSER, as discussed more in the following sections, is the relationship between the timing of measures and their effectiveness in limiting emissions. For example, actions that can occur in the near term, such as improvements to individual EGU heat rates, may fail to achieve the cumulative emission reductions that sustained implementation of other actions, such as demand-side energy efficiency programs, may achieve over time.

B. Building Blocks for the Best System of Emission Reduction

This subsection summarizes the EPA's analytic approach to determining the best system of emission reduction (BSER) for CO_2 emissions from existing EGUs. Later subsections discuss particular measures and how they form the basis of the BSER.[92]

1. Overview of Approach

In considering the appropriate scope of the proposed BSER, the EPA evaluated three basic groupings of strategies for reducing CO_2 emission from EGUs: (i) Reductions achievable through improvements in individual EGUs' emission rates (referred to throughout this preamble as ''building block 1''); (ii) EGU CO_2 emissions reductions achievable through re-dispatch from affected steam EGUs to affected NGCC units (''building block 2''); and (iii) EGU CO_2 emissions reductions achievable by meeting demand for electricity or electricity services through expanded use of low- or zero-carbon generating capacity (''building block 3'') and through expanded use of demand-side energy efficiency (''building block 4''). While the first grouping plays the same role in each of our two formulations of the BSER, the second and third groupings play different roles: In the first formulation they constitute components of the BSER, and in the second formulation they serve as the basis for why a component of that formulation of the BSER—reduced utilization of the higher-emitting affected EGUs—is adequately demonstrated.

As described in the remainder of this section, the EPA concluded that while certain strategies within the first grouping clearly should be part of the BSER, it was not appropriate to limit consideration of the BSER to this first grouping, for several reasons. First, we determined that some strategies available in the other two groupings can support reduced CO_2 emissions from the fossil fuel-fired EGUs by significant amounts and at lower costs than some of the strategies in the first grouping. Second, we observed that strategies in all three groupings were already being pursued by states and sources taking advantage of the integrated nature of the electricity system, at least in part for the purpose of reducing CO_2 emissions. Third, we were concerned that if measures from the first grouping that improve heat rates at coal-fired steam EGUs were implemented in isolation, without additional measures that encourage substitution of less carbon-intensive ways of providing electricity services for more carbon-intensive generation, the resulting increased efficiency of coal-fired steam units would provide incentives to operate those EGUs more, leading to smaller overall reductions in CO_2 emissions.[93] These factors reinforced the appropriateness of our considering strategies from all three groupings for purposes of determining the BSER.

2. CO_2 Reductions Achievable Through Improvements in Individual EGUs' Emission Rates

The first grouping of CO_2 emission reduction options that the EPA evaluated as potential options for the BSER consists of measures that can reduce individual EGUs' CO_2 emission rates (i.e., the amount of CO_2 emitted per unit of electricity [94] output). These measures included improving the efficiency with which EGUs convert fuel heat input to electricity output (i.e., heat rate improvements), applying carbon capture and storage (CCS) technology, and substituting lower-carbon fuels such as natural gas for higher-carbon fuels such as coal (i.e., natural gas co-firing or conversion).

Our assessment of heat rate improvements showed that these measures would achieve CO_2 emission reductions at low costs, although compared to other measures, the available reductions were relatively limited in quantity.[95] Specifically, our analysis indicated that average CO_2 emission reductions of 1.3 to 6.7 percent could be achieved by coal-fired steam EGUs through adoption of best practices, and that additional average reductions of up to four percent could be achieved through equipment upgrades.[96] Heat rate improvements pay for themselves at least in part through reductions in fuel costs, generally making this a relatively inexpensive approach for reducing CO_2 emissions. We estimated that CO_2 reductions of between four and six percent from overall heat rate improvements could be achieved on average across the nation's fleet of coal-fired steam EGUs for net costs in a range of $6 to $12 per metric ton.[97]

The EPA also examined application of CCS technology at existing EGUs. CCS offers the technical potential for CO_2 emission reductions of over 90 percent, or smaller percentages in partial applications. In the recently proposed Carbon Pollution Standards for new fossil fuel-fired EGUs (79 FR 1430), we found that partial CCS was adequately demonstrated for new fossil fuel-fired steam EGUs and integrated gasification

[92] The EPA is aware of the potential that one or more facilities involved in programs mentioned or relied on in this proposal may have received some form of assistance under the Energy Policy Act of 2005 (EPAct). Section 402 (i) of the EPAct (codified at 42 U.S.C. section 15962(i)) states:

''No technology, or level of emission reduction, solely by reason of the use of the technology, or the achievement of the emission reduction, by 1 or more facilities receiving assistance under this Act, shall be considered to be—(1) adequately demonstrated for purposes of section 111 of the Clean Air Act (42 U.S.C. 7411)[.]''

In a February 26, 2014 Notice of Data Availability, the EPA proposed to give this provision its natural meaning: the term ''solely'' modifies all of the provisions, so that any ''adequately demonstrated'' finding by the EPA could not be based solely upon technology, level of emission reduction, or achievement of the emission reduction by a facility (or facilities) receiving assistance. The EPA proposes the same interpretation here. The EPA further believes that its proposed determination of the ''best system of emission reduction . . . adequately demonstrated'' does not depend exclusively on technology, level of emission reduction, or achievement of emission reduction from facilities receiving EPAct assistance, given the myriad number of technologies and emission performance on which that proposed determination is based.

[93] Elsewhere in the preamble we refer to the potential for efficiency improvements to lead to increased competitiveness and therefore increased utilization as a ''rebound effect.''

[94] For simplicity, throughout this preamble we generally refer to the energy output produced by EGUs as electricity, recognizing that some EGUs produce a portion of their energy output in other forms, such as steam for heating or process uses. The discussion here applies to both EGUs that produce only electricity and EGUs that produce a combination of electricity and other energy output.

[95] The EPA assessed opportunities to achieve CO_2 reductions through heat rate improvements at both coal-fired steam EGUs and non-coal-fired fossil fuel-fired EGUs, such as oil/gas-fired steam EGUs and NGCC units. At this time we are proposing that the basis for supporting the BSER should include heat rate improvements only at coal-fired steam EGUs, but we are inviting comment on including heat rate improvements at other EGU types. See Section VI.C.5 for further discussion of our assessment of heat rate opportunities for non-coal-fired EGUs.

[96] These estimated ranges are averages applicable to the fleet of coal-fired steam EGUs as a whole. Potential improvements at individual EGUs could be higher or lower.

[97] As noted above, in the absence of other kinds of CO_2 emission reduction measures, the emission reductions achievable through heat rate improvements could be offset to some extent by increased utilization of EGUs making the improvements (a ''rebound effect''). See Section VI.C.1 below for further discussion.

combined cycle (IGCC) units. We also found that for these new units the costs were not unreasonable, either for individual units or on a national basis, and we proposed to find that application of partial CCS is the BSER. However, application of CCS at existing units would entail additional considerations beyond those at issue for new units. Specifically, the cost of integrating a retrofit CCS system into an existing facility would be expected to be substantial, and some existing EGUs might have space limitations and thus might not be able to accommodate the expansion needed to install CCS. Further, the aggregated costs of applying CCS as a component of the BSER for the large number of existing fossil fuel-fired steam EGUs would be substantial and would be expected to affect the cost and potentially the supply of electricity on a national basis. For these reasons, although some individual facilities may find implementation of CCS to be a viable CO_2 mitigation option in their particular circumstances,[98] the EPA is not proposing and does not expect to finalize CCS as a component of the BSER for existing EGUs in this rulemaking.[99] Nevertheless, CCS would be available to states and sources as a compliance option.

Natural gas co-firing or conversion at coal-fired steam EGUs offers greater potential CO_2 emission reductions than heat rate improvements, but at a higher cost (although less than the cost of applying CCS technology). Because natural gas contains less carbon than an energy-equivalent quantity of coal, converting a coal-fired steam EGU to burn only natural gas would reduce the unit's CO_2 emissions by approximately 40 percent. The CO_2 reductions are generally proportional to the amount of gas substituted for coal, so if an EGU continued to burn mostly coal while co-firing natural gas as, for example, 10 percent of the EGU's total heat input, the CO_2 emission reductions would be approximately four percent. The EPA determined that the most significant cost associated with natural gas conversion or co-firing is likely to be the incremental cost of natural gas relative to the cost of coal. Using Energy Information Administration (EIA) fuel price projections, we estimated that the CO_2 reductions achieved through natural gas conversion or co-firing at an average coal-fired steam EGU would have costs ranging from approximately $83 to $150 per metric ton.[100] Thus, although there have been past instances where coal-fired steam EGUs have been converted to natural gas, and we expect some additional future conversions where circumstances at individual EGUs make the option particularly attractive, for the industry as a whole we would expect that other approaches could reduce CO_2 emissions from existing EGUs at lower cost. However, gas conversion or co-firing would be available to states and sources as a compliance option, and, as noted later in the preamble, we are seeking comment on whether this option should be considered part of the BSER.

3. CO_2 Emission Reductions Achievable Through Re-Dispatch From Steam EGUs to NGCC Units

The second grouping of CO_2 emission reduction options evaluated by the EPA in the BSER analysis involves reducing emissions by shifting generation among affected EGUs. An obvious alternative to substituting natural gas for coal at individual steam EGUs through conversion or co-firing is instead to use natural gas to generate electricity at a different affected EGU with a better heat rate—notably a natural gas combined cycle (NGCC) unit—and to substitute that electricity for electricity from the coal-fired steam EGU, thus resulting in lower emissions from the coal-fired steam EGU and lower emissions from the set of affected EGUs overall.[101] The electricity system is physically interconnected or networked and operated on an integrated basis across large regions. System operators routinely increase or decrease the electricity output of individual EGUs to respond to changes in electricity demand, equipment availability, and relative operating costs (or bid prices) of individual EGUs while observing reliability-related constraints. It has long been common industry practice for system operators to choose from among multiple EGUs when deciding which EGU to ''dispatch'' to generate the next increment of electricity needed to meet demand. Thus, the well-established practices of the industry support our evaluation of ''re-dispatch'' of generation from steam EGUs to NGCC units as a potential component of the basis for the BSER to reduce CO_2 emissions from existing EGUs.

NGCC units can produce as much as 46 percent more electricity from a given quantity of natural gas than steam EGUs,[102] making the re-dispatch approach a significantly less expensive way to reduce CO_2 emissions than conversion or co-firing of coal-fired steam EGUs to burn natural gas. For example, using the same EIA fuel cost projections as were used above to estimate the costs of natural gas conversion or co-firing, we estimated that the cost of CO_2 reductions achievable by substituting electricity from an existing NGCC unit for electricity from an average coal-fired steam EGU would be approximately $30 per metric ton.[103]

Our analysis indicated that the potential CO_2 reductions available through re-dispatch from steam EGUs to NGCC units are substantial. As of 2012, there was approximately 245 GW of NGCC capacity in the United States, 196 GW of which was placed in service between 2000 and 2012.[104] In 2012, the average utilization rate of U.S. NGCC capacity was 46 percent, well below the utilization rates the units are capable of achieving. In 2012 approximately 10 percent of NGCC plants operated at annual utilization rates of 70 percent or higher, and 19 percent of NGCC units operated at utilization rates of at least 70 percent over the summer season. Average reported availability generally exceeds 85 percent. We recognize that the ability to increase NGCC utilization rates may also be affected by infrastructure and system considerations, such as limits on the ability of the natural gas industry to produce and deliver the increased quantities of natural gas, the ability of steam EGUs to reduce generation while remaining ready to supply electricity when needed in peak demand hours, and the ability of the electric transmission system to accommodate the changed geographic pattern of generation. However, these considerations have not limited past rapid increases in NGCC generation levels, as indicated by a 20 percent increase in natural gas consumption for

[98] CCS already has been or is being implemented at some existing EGUs, as noted in the discussion of CCS later in the preamble.

[99] As noted later in this preamble, we are nevertheless seeking comment on the extent to which existing EGUs could implement CCS in order to improve our understanding.

[100] The lower end of the range is for conversion to 100 percent natural gas, which would allow EGUs to eliminate certain fixed operating and maintenance costs associated with coal use but not natural gas use. See Section VI.C.5.a below for further discussion.

[101] Strategies in this grouping also include shifting generation from steam EGUs burning oil or natural gas to more efficient NGCC units.

[102] This estimate assumes an average heat rate of 10,434 Btu/kWh for coal fossil fuel-fired steam units between 400 and 600 MW and 7,130 Btu/kWh for NGCC units between 400 and 600 MW. See NEEDSv.5.13 at *http://www.epa.gov/powersectormodeling/BaseCasev513.html.*

[103] See Section VI.C.2 below for further discussion.

[104] EIA Form 860, available at *http://www.eia.gov/electricity/data/eia860.* In comparison, in 2012 there was 336 GW of coal steam capacity, of which 22 GW was placed in service between 2000 and 2012. Id.

electricity generation from 2011 to 2012.[105] Further, we have taken these considerations into account, and the proposal's compliance schedule provides flexibility and time for investment in additional natural gas and electric industry infrastructure if needed.

As discussed below in Section VI.C.2, the data and considerations cited above support our assessment that an average NGCC utilization rate in a range of 65 to 75 percent is a reasonable target for the amount of additional NGCC generation that could be substituted for higher carbon generation from steam EGUs as part of the BSER.[106] If re-dispatch consistent with a target average NGCC utilization rate of 70 percent had been achieved in 2012, the combined CO_2 emissions of steam EGUs and NGCCs would have been reduced by approximately 13 percent.

Finally, we also note that mechanisms for encouraging re-dispatch as a CO_2 reduction measure have already been developed and applied in the industry. Under both RGGI and California's Global Warming Solutions Act, shifting generation from more carbon-intensive EGUs to less carbon-intensive EGUs is a way to facilitate compliance with regulatory requirements. In both cases, the industry has demonstrated the ability to respond to the regulatory requirements of these state programs.

4. CO_2 Emission Reductions Achievable Through Other Actions Underway in the Industry

The third grouping of CO_2 emission reduction options the EPA evaluated in the BSER analysis encompasses other measures already used in the industry and not included in the first two groupings. From our evaluation of re-dispatch as an option for reducing CO_2 emissions, it was apparent that relevant factors for consideration include the integrated nature of the electricity system and the fact that particular measures capable of reducing CO_2 emissions at EGUs were already being used and would continue to be used throughout the industry, either for the purpose of compliance with CO_2 emission reduction requirements or to serve other purposes and policy goals. That observation led us to consider what other potential actions and options the industry was already using that had resulted in or could result in, or support, the reduction of CO_2 emissions at EGUs. Again, we observed many such instances, some taking place incidental to the routine operation of the electricity system and others taking place in response to specific state initiatives to reduce CO_2 emissions from the power sector. We concluded that there are two principal types of such potential options for measures that support CO_2 emission reductions at EGUs affected under this proposal: Ongoing development and use of low- and zero-carbon generating capacity, and ongoing development and application of demand-side energy efficiency measures.

Low-and zero-carbon generating capacity provides electricity that can be substituted for generation from more carbon-intensive EGUs. More than half the states already have established some form of state-level renewable energy requirements, with targets calling on average for almost 20 percent of 2020 generation to be supplied from renewable sources. The EPA is unaware of analogous state policies to support development of new nuclear units, but 30 states already have nuclear EGUs (with five units under construction) and the generation from these units is currently helping to avoid CO_2 emissions from fossil fuel-fired EGUs. Policies that encourage development of renewable energy capacity and discourage premature retirement of nuclear capacity could be useful elements of CO_2 reduction strategies and are consistent with current industry behavior. Costs of CO_2 reductions achievable through these policies have been estimated in a range from $10 to $40 per metric ton.[107]

Demand-side energy efficiency programs produce electricity-dependent services with less electricity, and thereby support reduced generation from existing fossil fuel-fired EGUs by reducing the demand for that generation. Reduced generation results in lower CO_2 emissions. More than 40 states already have established some form of demand-side energy efficiency polices, and individual states have avoided up to 13 percent of their electricity demand. Again, policies that encourage demand-side energy efficiency could be useful elements of CO_2 reduction strategies and are consistent with current industry behavior. Using conservatively high estimates of the costs of demand-side energy efficiency, the EPA estimates that the costs of CO_2 emission reductions achievable consistent with such policies would be in a range of $16 to $24 per metric ton.[108]

5. Summary of Building Blocks for the Best System of Emission Reduction

Based on the analytic approach summarized above, the EPA has identified the following four principal categories—''building blocks''—of measures that provide the foundation of our BSER determination for CO_2 emissions from existing EGUs:

1. Reducing the carbon intensity of generation at individual affected EGUs through heat rate improvements.
2. Reducing emissions from the most carbon-intensive affected EGUs in the amount that results from substituting generation at those EGUs with generation from less carbon-intensive affected EGUs (including NGCC units under construction).
3. Reducing emissions from affected EGUs in the amount that results from substituting generation at those EGUs with expanded low- or zero-carbon generation.
4. Reducing emissions from affected EGUs in the amount that results from the use of demand-side energy efficiency that reduces the amount of generation required.

Since they either result in improved operating efficiency or support reductions in mass emissions at existing EGUs, each of the four building blocks represents a demonstrated basis for reducing CO_2 emissions from affected EGUs that is already being pursued in the power sector. In the next subsection, we discuss each of the building blocks at length. Our approach for applying the building blocks to each state's circumstances in order to develop state goals is described in Section VII of this preamble.

C. Detailed Discussion of Building Blocks and Other Options Considered

In this subsection we discuss each of the building blocks in turn. For each building block, we provide our proposed assessment of the technical potential of the building block and the reasonableness of its costs within the context of the BSER determination, and we describe how we developed the data inputs used in the computations of the proposed state goals described in Section VII.C and the alternate goals offered for comment in Section VII.E. We also discuss certain measures that we are not proposing to consider as part of the best system of emission reduction. Additional detail is provided

[105] EIA Form 923, available at *http://www.eia.gov/electricity/data/eia923/*.

[106] Substitution would only occur to the extent that there is both NGCC capacity whose generation could be increased and steam EGUs whose generation could be decreased.

[107] See Section VI.C.3 below for further discussion.

[108] See Section VI.C.4 below for further discussion.

in the Greenhouse Gas Abatement Measures TSD.

It is worth noting that although the discussion below necessarily addresses the building blocks individually, states are not required to pursue plans involving any given building block or to do so at any particular level of stringency. Rather, states have flexibility to establish plans to meet their state emission limitations using their own preferred combinations of efficacious measures applied to the extent determined appropriate by the states. The EPA expects that states and affected EGUs are unlikely to limit themselves to the measures in any single building block, but instead are likely to pursue portfolios of measures from a combination of the actions encompassed in the building blocks. In developing the data inputs to be used in computing state goals, the EPA has estimated reasonable rather than maximum possible implementation levels for each building block in order to establish overall state goals that are achievable while allowing states to take advantage of the flexibility to pursue some building blocks more extensively, and others less extensively, than is reflected in the goal computations, according to each state's needs and preferences.

1. Building Block 1—Heat Rate Improvements

The first category of approaches to reducing CO_2 emissions at affected fossil fuel-fired EGUs consists of measures that reduce the carbon intensity of generation at individual coal-fired steam EGUs [109] by improving heat rate. Heat rate improvements are changes that increase the efficiency with which an EGU converts fuel energy to electric energy (and useful thermal energy in the case of units that cogenerate steam for process use as well as electricity), thereby reducing the amount of fuel needed to produce the same amount of electricity and lowering the amount of CO_2 produced as a byproduct of fuel combustion. Heat rate improvements yield important benefits to affected sources by reducing their fuel costs.

The EPA is aware of the potential for ''rebound effects'' from improvements in heat rates at individual EGUs. In this context, a rebound effect would occur where, because of an improvement in its heat rate, an EGU experiences a reduction in variable operating costs that makes the EGU more competitive relative to other EGUs and consequently raises the EGU's generation output. The increase in the EGU's CO_2 emissions associated with the increase in generation output would offset the reduction in the EGU's CO_2 emissions caused by the decrease in its heat rate and rate of CO_2 emissions per unit of generation output. The extent of the offset would depend on the extent to which the EGU's generation output increased (as well as the CO_2 emission rates of the EGUs whose generation was displaced). The EPA considers the rebound effect to be a potential concern if heat rate improvements were the only approaches being considered for the BSER, but believes that the effect can be addressed by establishing the BSER as a combination of approaches that includes not only heat rate improvements but also approaches that will encourage reductions in electricity demand or increases in generation from lower- or zero-emitting EGUs. The topic of potential rebound effects is discussed further in Sections VI.D and VI.E below. For purposes of the remainder of this subsection, no rebound effect is assumed.

Although heat rate improvements have the potential to reduce CO_2 emissions from all types of affected EGUs, the EPA's analysis indicates the potential is significantly greater for coal-fired steam EGUs than for other EGUs, and for purposes of determining the best system of emission reduction at this time, the EPA is conservatively proposing to base its estimate of CO_2 emission reductions from heat rate improvements on coal-fired steam EGUs only.[110] The remainder of this subsection focuses on the EPA's analysis of potential heat rate improvements from coal-fired steam EGUs. Our analysis of potential heat rate improvements from other types of affected EGUs is addressed in Section VI.C.5 below.

a. Ability of Heat Rate Improvements To Reduce CO_2 Emissions

The heat rate of an EGU is the amount of fuel energy input needed (Btu, higher heating value basis) to produce 1 kWh of net electrical energy output (and useful thermal energy in the case of cogeneration units).[111] The current weighted-average annual heat rate of U.S. coal-fired EGUs in the range of 400 to 600 MW is approximately 10,434 Btu per net kWh.[112] Because an EGU's CO_2 emissions are driven primarily by the amount of fuel consumed, at any fossil fuel-fired EGU there is a strong correlation between potential heat rate improvements and potential reductions in carbon-intensity.[113]

Several studies have examined the opportunities to employ heat rate improvements as a means of reducing CO_2 emissions from coal-fired power plants.[114] Among these, a 2009 study by the engineering firm Sargent & Lundy used bottom-up engineering approaches evaluating potential heat rate improvements from specific best practices and equipment upgrades, including upgrades to boilers, steam turbines, and control systems. Based on this study, the EPA believes that implementation of all identified best practices and equipment upgrades at a facility could provide total heat rate improvements in a range of approximately 4 to 12 percent. (We recognize that individual EGUs would only be able to implement the best practices or upgrades that were applicable to their specific designs or fuel types and that had not already been implemented.)

In addition to the Sargent & Lundy study, which looked generically at the types of improvements that can be made at specific types of EGUs, historical heat rate data also provides a basis for

[109] A ''steam EGU'' is an EGU that combusts fuel in a boiler and uses the combustion heat to create steam which is then used to drive a steam turbine that drives a generator to create electricity. In contrast, a ''combined cycle EGU'' combusts fuel in a combustion turbine that directly drives a generator, and the waste heat is then used to create steam which is used to drive a steam turbine that drives a generator to create more electricity. Steam EGUs can combust a wide variety of fuels including coal and natural gas. Combined cycle EGUs are more efficient at converting fuel energy to electric energy but are limited to gaseous or liquid fuels, most commonly natural gas or distillate oil. Almost all existing coal-fired EGUs are steam EGUs (the exceptions are integrated gasification combined cycle (IGCC) units where coal is processed to create a gaseous fuel that is then combusted in a combined cycle unit).

[110] As noted in Section VI.C.5.d below, we are taking comment on including heat rate improvement opportunities at other EGU types in the basis for supporting the BSER. Also, for compliance purposes states and EGUs would be able to rely on CO_2 emission reductions achieved through heat rate improvements at other types of EGUs.

[111] Heat rate can also be expressed on a gross basis—i.e., fuel input per kWh of gross electricity generated—instead of a net basis—i.e., fuel input per kWh of net electricity sent to the grid. The difference between gross and net electricity is the amount of electricity used at the plant to operate components such as pumps, fans, motors, and pollution control devices.

[112] See NEEDSv.5.13 at *http://www.epa.gov/powersectormodeling/BaseCasev513.html.*

[113] A small portion of some fossil fuel-fired EGU's CO_2 emissions may come from sources other than fuel, such as limestone or other carbonates used to capture sulfur dioxide (SO_2) and/or hydrogen chloride (HCl) in a scrubber or dry injection system. However, CO_2 emissions from these reagents will also tend to be reduced by heat rate improvements, because reagent usage, and the associated CO_2 emissions, will decrease when the amount of fuel used decreases.

[114] See chapter 2 of the GHG Abatement Measures TSD for details.

discerning the existence and possible magnitude of potential heat rate improvements. Many EGUs regularly report to both the EPA and the U.S. Department of Energy's Energy Information Administration (EIA) CO_2 emissions and generation data, from which heat input and heat rate data can be computed. We have reviewed these data and have identified several ''data apparent'' instances where an EGU's heat rate experienced a substantial improvement in a short time—presumably because of equipment upgrades installed at that point in time—that was then sustained. These heat rate improvements ranged from 3 to 8 percent. In combination with bottom-up engineering analysis and the further, more detailed EPA analysis of hourly data summarized below, the individual EGU heat rate histories provide a strong basis for considering heat rate improvement as a meaningful potential approach to reducing the carbon intensity of generation at individual affected fossil fuel-fired EGUs.

b. Amounts of Heat Rate Improvements

In order to estimate the technical potential of heat rate improvement opportunities at existing fossil fuel-fired EGUs suggested by the discussion above, the EPA pursued two principal areas of analysis. The first area concerned the heat rate improvements that could be achieved by reducing heat rate variability at individual coal-fired EGUs through adoption of best practices for operation and maintenance. The second area concerned heat rate improvement opportunities that could be achieved through further equipment upgrades. Both analyses are summarized below along with our conclusions, and are discussed in greater detail in the GHG Abatement Measures TSD.

For the best practices analysis, the EPA worked with the hourly data reported to the EPA by affected EGUs subject to the monitoring and reporting requirements of 40 CFR Part 75. The reported data include hourly heat input and, for most reporting EGUs, hourly gross generation, making it possible to compute hourly gross heat rates. We used the hourly data to assess variability in the hourly gross heat rates of approximately 900 individual coal-fired steam EGUs over the period from 2002 to 2012. Specifically, the EPA evaluated the consistency with which individual EGUs maintained their hourly heat rates over time. We expected that a certain degree of short-term heat rate variability was caused by factors beyond operators' control, notably variation in hourly ambient temperature and hourly load, and preliminary analysis confirmed our expectation. We therefore controlled for variation in those factors by grouping the observed hourly heat rate data for each EGU into subsets corresponding to ranges of hourly ambient temperatures and hourly load levels.[115] We believe that the amount of residual variability within each data subset is an indication of the degree of technical potential to improve the consistency with which optimal heat rate performance is achieved by adopting operating and maintenance best practices. For example, optimal heat rate performance could be achieved with greater consistency through practices such as turning off unneeded pumps at reduced loads, installation of digital control systems, more frequent tuning of existing control systems, or earlier like-kind replacement of worn existing components. (Upgrades to existing equipment are considered below.) By applying best practices to their operating and maintenance procedures, owners and operators of EGUs could reduce heat rate variability relative to average heat rates and, because the deviations generally result in performance worse than the optimal heat rates, improve the EGUs' average heat rates. Assuming that between 10 percent and 50 percent of the deviation from top decile performance in each subset of hourly heat rate observations within defined ranges of temperature and load could be eliminated through adoption of best practices, the result is a corresponding estimated range of 1.3 percent to 6.7 percent technical potential for improvement in the average heat rate of the entire fleet of coal-fired EGUs.[116] Based on this analysis, we believe a reasonable estimate for purposes of developing state-specific goals is that affected coal-fired steam EGUs on average could achieve a four percent improvement in heat rate through adoption of best practices to reduce hourly heat rate variability. This estimate corresponds to the elimination, on average across the fleet of affected EGUs, of 30 percent of the deviation from top-decile performance in the hourly heat rate for each EGU not attributable to hourly temperature and load variation. We also solicit comment on the use of estimates up to six percent, reflecting elimination on average of 50 percent of the deviation from top-decile performance.

For the equipment upgrade analysis, we evaluated potential opportunities to improve heat rates at affected EGUs through specific upgrades identified in the 2009 Sargent & Lundy study. In that study, Sargent & Lundy estimated ranges of potential heat rate improvement achievable through a variety of equipment upgrades. We screened the upgrades from the study to identify what we consider to be a reasonable subset of equipment upgrades that would generally be beyond the scope of investments we would expect to be made for purposes of achieving the best-practices heat rate improvements discussed above. Based on the average of the study's ranges of potential heat rate improvements from the various upgrades in this subset, implementation of the full subset of appropriate opportunities at a single EGU could be expected to result in an aggregate heat rate improvement of approximately four percent (incremental to the improvement achievable from adoption of best practices). However, we recognize that this total may overstate the average equipment upgrade opportunity across all EGUs because some EGUs may have already implemented some of these upgrades. We therefore propose to use as a data input for purposes of developing state goals an estimate that, on average across the fleet of affected EGUs, only half of the full equipment upgrade opportunity just described remains—i.e., that for the fleet of affected EGUs as a whole, the technical potential for heat rate improvements from equipment upgrades incremental to the best-practices opportunity is on average two percent rather than four percent. We solicit comment on increasing this figure up to four percent.

Some of the measures available to EGUs for reducing their carbon intensity affect net heat rates rather than gross heat rates. Various EGU components such as pumps, fans, motors, and pollution control devices use electricity, a factor that is not accounted for in gross heat rates (that is, fuel used per unit of gross energy output) but is accounted for in net heat rates (that is, fuel used per unit of net energy output sent to the electric grid or used for thermal purposes). The electricity used by these components, referred to as auxiliary or parasitic load, may represent from 4 to 12 percent of gross generation at a coal-fired steam EGU.[117] The analysis of

[115] Temperature data are from the National Oceanic and Atmospheric Administration's Integrated Surface Data, *http://www.ncdc.noaa.gov/data-access/land-based-station-data/land-based-datasets/integrated-surface-database-isd*. Electrical generation data are from the EPA's Air Markets Program Data, *http://ampd.epa.gov/ampd/*.

[116] We examined whether the potential for heat rate improvement varied based on EGU characteristics such as capacity, boiler type, and location, and found no meaningful differences.

[117] Electric Power Research Institute 2011 Technical Report—Program on Technology Innovation: Electricity Use in the Electric Sector

technical potential to reduce heat rate variability discussed above was based on gross heat rate data. Like gross heat rate, parasitic load can be addressed both through adoption of best practices and through equipment upgrades, and some measures undertaken at EGUs may affect parasitic load as well as gross heat rate. Because the hourly generation data reported to the EPA represent gross generation, we have less data available to directly analyze potential net heat rate improvements than gross heat rate improvements. We have therefore not included any separate estimate of parasitic load reductions achievable through best practices in our goal-setting data inputs. However, these opportunities would be available as a mechanism for reducing carbon-intensity at affected EGUs and thus provide more flexibility and opportunities for sources to improve their heat rates at reasonable costs.[118]

The total of the estimated potential heat rate improvements from adoption of best practices to reduce heat rate variability and implementation of equipment upgrades as discussed above is six percent. This total is used as the data input for heat rate improvements in the computation of proposed state goals discussed in Section VII.C below. Because of the close relationship between an EGU's fuel consumption and its CO_2 emissions, a six percent heat rate improvement would be associated with a reduction in CO_2 emissions of approximately six percent. We believe that this represents a reasonable estimate of the technical potential for CO_2 emission reductions that would be achievable from affected coal-fired steam EGUs, on average, through heat rate improvements as an element of the best system of emission reduction.

For purposes of developing the alternate set of goals on which we are taking comment, as described in Section VII.E below, we have used a more conservative estimate of a four percent heat rate improvement from affected coal-fired EGUs on average. This level of improvement would be consistent with those EGUs on average implementing best practices to reduce heat rate variability without making further equipment upgrades, or would be consistent with those EGUs on average implementing both best practices and equipment upgrades, but to a lesser degree than we have projected as being achievable for purposes of our proposal. We view the four percent estimate as a reasonable minimum estimate of the technical potential for heat rate improvement on average across affected coal-fired steam EGUs.

c. Costs of Heat Rate Improvements

By definition, any heat rate improvement made for the purpose of reducing CO_2 emissions will also reduce the amount of fuel the EGU consumes to produce its electricity output. The cost attributable to CO_2 emission reductions therefore would be the net cost to achieve the heat rate improvement after any savings from reduced fuel expense. As summarized below, we estimate that, on average, the savings in fuel cost associated with a six percent heat rate improvement would be sufficient to cover much of the associated costs, with the result that the net costs of heat rate improvements associated with reducing CO_2 emissions from affected EGUs are relatively low.

The EPA's most detailed estimates of the average costs required to achieve the full range of heat rate improvements come from the 2009 Sargent & Lundy study discussed above. Based on the study, the EPA estimated that for a range of heat rate improvements from 415 to 1205 Btus per kWh, corresponding to percentage heat rate improvements of 4 to 12 percent for a typical coal-fired EGU, the required capital costs would range from $40 to $150 per kW. To correspond to the average heat rate improvement of six percent that we have estimated to be achievable through the combination of best practices and equipment upgrades, we have estimated an average cost of $100 per kW, slightly above the midpoint of the Sargent & Lundy study's range. At an estimated annual capital charge rate of 14.3 percent, the carrying cost of an estimated $100 per kW investment would be $14.30 per kW-year. For a coal-fired EGU with a heat rate of 10,450 Btu per kWh, a utilization rate of 78 percent, and a coal price of $2.62 per MMBtu, a six percent heat rate improvement would produce fuel cost savings of approximately $11.20 per kW-year,[119] leaving approximately $3.10 per kW-year of carrying cost not recovered through fuel cost savings. At an average CO_2 emission rate of 0.976 metric tons per MWh, the same six percent heat rate improvement would reduce CO_2 emissions by 0.40 metric tons per kW-year.[120] Thus, the average cost of CO_2 reductions from heat rate improvements would be approximately $7.75 per metric ton of CO_2 ($3.10/0.40). If the average heat rate improvement achievable for the $100 per kW investment were only four percent, consistent with the heat rate improvement estimate in the alternate goals on which we seek comment, the average cost of CO_2 reductions would be $11.63 per metric ton.[121] On the other hand, if an average heat rate improvement of four percent could be achieved for an average investment of $50 per kW, reflecting an assumption that the first improvements pursued would be the least expensive ones, the average cost of CO_2 reductions would fall to $5.81 per metric ton.[122]

The EPA recognizes that the simplified cost analysis just described will represent the costs for some EGUs better than others because of differences in EGUs' individual circumstances. We further recognize that reductions in the utilization rates of coal-fired EGUs anticipated from other components proposed for inclusion in the best system of emission reduction would tend to reduce the fuel savings associated with heat rate improvements, thereby raising the effective cost of achieving the CO_2 emission reductions from the heat rate improvements. Nevertheless, we still expect that the majority of the investment required to capture the technical potential for CO_2 emission reductions from heat rate improvements would be offset by fuel savings, and that the net costs of heat rate improvements as an approach to reducing CO_2 emissions from existing fossil fuel-fired EGUs are reasonable.

Based on the analyses of technical potential and cost summarized above, we propose to find that a six percent reduction in the CO_2 emission rate of the coal-fired EGUs in a state, on average, is a reasonable estimate of the amount of heat rate improvement that can be implemented at a reasonable cost.[123]

(Opportunities to Enhance Electric Energy Efficiency in the Production and Delivery of Electricity).

[118] As proposed, the state-specific goals are expressed in the form of CO_2 emissions per net MWh, and reporting requirements for sources would be in the same form, allowing parasitic load reductions to contribute to improved measured heat rates. If goals and reporting requirements were changed to a gross MWh basis in the final rule, accounting for parasitic load reductions as a source of CO_2 reductions would require additional procedures.

[119] 10,450 Btu/kWh * 8760 hours/year * 78% utilization * $2.62 per MMBtu * 6% improvement * 0.000001 MMBtu/Btu = $11.2 per kW-year. Data inputs for average coal-fired EGU heat rate, average coal-fired EGU utilization, and average coal price are from the IPM 5.13 base case for 2020.

[120] 8760 hours/year * 78% utilization * 0.976 metric tons/Mwh * 6% improvement * 0.001 MW/kW = 0.40 metric tons of CO_2 per kW-year. The estimated average coal-fired EGU CO_2 emission rate per MWh is from the IPM 5.13 base case for 2020.

[121] $7.75 per metric ton of CO_2 * 6%/4% = $11.63 per metric ton of CO_2.

[122] $11.63 per metric ton of CO_2 * $50/$100 = $5.81 per metric ton of CO_2.

[123] We note that although we expect that heat rate improvements are also available from other fossil

Continued

We invite comment on all aspects of our analyses and findings related to heat rate improvements, both as summarized here and as further discussed in the Greenhouse Gas Abatement Measures TSD. As noted earlier, we specifically request comment on increasing the estimates of the amounts of heat rate improvement achievable through adoption of best practices for operation and maintenance and through equipment upgrades up to six percent and four percent, respectively, representing a total potential improvement of up to ten percent, particularly in light of the reasonable cost of heat rate improvements. We also solicit comment on the quantitative impacts on the net heat rates of coal-fired steam EGUs of operation at loads less than the rated maximum unit loads.

2. Building Block 2—Dispatch Changes Among Affected EGUs

The second element of the foundation for the EPA's BSER determination for reducing CO_2 emissions at affected fossil fuel-fired EGUs goes to the achievement of reductions in mass emissions at certain affected EGUs—in particular, fossil fuel-fired steam EGUs—and entails an analysis of the extent to which generation at the most carbon-intensive affected EGUs—again, in particular, fossil fuel-fired steam EGUs—can be replaced with generation at less carbon-intensive affected fossil fuel-fired EGUs—in particular, NGCC units that were in operation or had commenced construction as of January 8, 2014, and are therefore affected units for purposes of this rule.

a. Ability of Re-Dispatch To Reduce CO_2 Emissions

The nation's EGUs are interconnected by transmission grids extending over large regions. EGU owners and grid operators, subject to various reliability and operational constraints, use the flexibility provided by these interconnections to prioritize among available EGUs when deciding which units should be called upon (i.e., ''dispatched'') to increase or decrease generation in order to meet electricity demand at any point in time. Recognizing that increments of generation are to some extent interchangeable, dispatch decisions are based on electricity demand at a given point in time, the variable costs of available generating resources, and system constraints. This system of security-constrained economic dispatch assures reliable and affordable electricity. Electricity demand varies across geography and time in response to numerous conditions, such that EGU owners and grid operators are constantly responding to changes in demand and ''re-dispatching'' to meet demand in the most reliable and cost-effective manner possible. Since the enactment and implementation of Title IV of the CAA Amendments of 1990, in regions where EGUs are subject to market-based programs to limit emissions of pollutants such as SO_2 and NO_X, the costs of emission allowances have been factored directly into those EGUs' variable costs, like the variable costs of operating pollution control devices, and have thereby been accounted for in least-cost economic dispatch decisions by grid operators. Similarly, operators of EGUs subject to CO_2 emissions limits in RGGI now include the cost of RGGI CO_2 allowances in those EGUs' variable costs,[124] creating economic incentives to replace generation at higher-emitting EGUs with generation from lower-emitting sources to reduce CO_2 emissions at the former through the process of least-cost economic dispatch. As an alternate mechanism, permitting authorities can impose limits on utilization or CO_2 emissions at higher-emitting EGUs, in which case grid operators and other market participants would use the integrated electricity system to find other ways to meet the demand for electricity services, either through demand-side energy efficiency or through increased generation from lower-emitting EGUs. In either case, whether implemented through economic mechanisms or permit limitations, reducing emissions at high carbon-intensity EGUs is technically feasible and can reduce overall power sector CO_2 emissions because generation at such EGUs can be replaced by generation at less carbon-intensive EGUs.

We have also analyzed potential upstream net methane emissions impact from natural gas and coal for the impacts analysis. This analysis indicated that any net impacts from methane emissions are likely to be small compared to the CO_2 emissions reduction impacts of shifting power generation from coal-fired steam EGUs to NGCC units. Further information on our analysis of upstream impacts can be found in Appendix 3A of the RIA.

b. Magnitude of Re-Dispatch

Having identified replacing generation at higher-emitting EGUs with generation at lower-emitting EGUs as a technically feasible CO_2 emissions reduction strategy, we next address the quantity of replacement generation that may be relied upon at reasonable costs. The U.S. electric generating fleet includes EGUs employing a variety of generating technologies. EGUs using technologies with relatively low variable costs, such as nuclear units, are for economic reasons generally operated at their maximum output whenever they are available. Renewable EGUs such as wind and solar units also have low variable costs, but in any event are generally operated when wind and sun conditions permit rather than at operators' discretion. In contrast, fossil fuel-fired EGUs have higher variable costs and are also relatively flexible. Fossil fuel-fired EGUs are therefore generally the units that operators use to respond to intra-day and intra-week changes in demand. Because of these typical characteristics of the various EGU types, the primary re-dispatch opportunities among existing units available to EGU owners and grid operators generally consist of opportunities to shift generation among various fossil fuel-fired units, in particular between coal-fired EGUs (as well as oil- and gas-fired steam EGUs) and NGCC units. In the shortterm—that is, over time intervals shorter than the time required to build a new EGU—fossil fuel-fired units consequently tend to compete more with one another than with nuclear and renewable EGUs. The amount of re-dispatch from coal-fired EGUs to NGCC units that takes place as a result of this competition is highly relevant to overall power sector GHG emissions, because a typical NGCC unit produces less than half as much CO_2 per MWh of electricity generated as a typical coal-fired EGU.

In order to estimate the potential magnitude of the opportunity to reduce power sector CO_2 emissions through re-dispatch among existing EGUs, the EPA first examined information on the design capabilities and availability of NGCC units. This examination showed that, although most NGCC units have historically been operated in intermediate-duty roles for economic reasons, they are technically capable of

fuel-fired EGUs, we have conservatively not included CO_2 emission rate reductions for those EGUs in the state goals. However, as discussed in Section VI.C.5.d below, we are requesting comment on this aspect of the proposal. Further, states and sources would be free to use heat rate improvements at those other units to help reach the state goals.

[124] The PJM market monitor publishes breakdowns of wholesale energy prices, including a CO_2 emission allowance cost component, based on analysis of the prices bid by the ''marginal'' EGUs. See Monitoring Analytics, 2013 State of the Market Report for PJM at 103–05, tbls. 3–63 & 3–64 (2014), available at *http://www.monitoringanalytics.com/reports/pjm_state_of_the_market/2013.shtml*.

operating in base-load roles at much higher annual utilization rates. Average annual availability (that is, the percentage of annual hours when an EGU is not in a forced or maintenance outage) for NGCC units in the U.S. generally exceeds 85 percent, and can exceed 90 percent for some groups.[125]

We also researched historical data to determine the utilization rates that NGCC units have already been demonstrated capable of sustaining. Over the last several years, EGU owners and grid operators have engaged in considerable re-dispatch among various types of fossil fuel-fired units relative to historical dispatch patterns, with NGCC units increasing generation and many coal-fired EGUs reducing generation. In fact, in April 2012, for the first time ever the total quantity of electricity generated nationwide from natural gas was approximately equal to the total quantity of electricity generated nationwide from coal.[126] These changes in generation patterns have been driven largely by changes over time in the relative prices of natural gas and coal, in addition to lower overall demand for electricity. Although the relative fuel prices vary by location, as do the recent patterns of re-dispatch, this trend holds across broad regions of the U.S. In the aggregate, the historical data provide ample evidence indicating that, on average, existing NGCC units can achieve and sustain utilization rates higher than their present utilization rates.

The experience of relatively heavily used NGCC units provides an additional indication of the degree of increase in average NGCC unit utilization that is technically feasible. According to the historical NGCC unit utilization rate data reported to the EPA, in 2012 roughly 10 percent of existing NGCC units operated at annual utilization rates of 70 percent or higher.[127] In effect, these units were being dispatched to provide base-load power. In addition to the 10 percent of NGCC units that operated at a 70 percent utilization rate on an annual basis, some NGCC units operated at high utilization rates for shorter, but still sustained, periods of time in response to high cyclical demand. For example, on a seasonal basis, a significant number of NGCC units have achieved utilization rates between 50 and 80 percent; over the 2012 winter season (December 2011–February 2012) and summer season (June–August 2012), about 16 percent and 19 percent of NGCC units, respectively, operated at utilization rates of 70 percent or more across these entire seasons.[128] During the spring and fall periods when electricity demand levels are typically lower, these units were sometimes idled or operated at much lower capacity factors. Nonetheless, the data clearly demonstrate that a substantial number of existing NGCC units have proven the ability to sustain 70 percent utilization rates for extended periods of time. We view this as strong evidence that increasing the utilization rates of existing NGCC units to 70 percent, not in every individual instance but on average, as part of a comprehensive approach to reducing CO_2 emissions from existing high carbon-intensity EGUs, would be technically feasible.

For purposes of establishing state goals, historical (2012) electric generation data are used to apply each building block and develop each state's goal (expressed as an adjusted CO_2 emission rate in lbs per MWh).[129] In 2012, total electric generation from existing NGCC units was 959 TWh.[130] After the application of NGCC re-dispatch toward a 70 percent target utilization rate, the total generation from these existing sources is projected to be 1,390 TWh per year. Adding in the NGCC units that had commenced construction before January 8, 2014 (and are therefore existing sources for purposes of this proposal) but were not yet in operation in 2012 increases the projected total generation from the full set of existing NGCC units to 1,443 TWh per year.

Although producing over 1,400 TWh of generation in 2020 from existing NGCC units is not actually required, because states may choose other abatement measures to reach the state goals, the EPA nevertheless believes that producing this quantity of generation from this set of NGCC units is feasible. As a reference point, NGCC generation increased by approximately 430 TWh (an 80 percent increase) between 2005 and 2012. The EPA calculates that NGCC generation in 2020 could increase by approximately 50 percent from today's levels. This reflects a smaller ramp-up rate in NGCC generation than has been observed from 2005 to 2012. We also expect an increase in NGCC generation of this amount would not impair power system reliability. As we note in the TSD on Resource Adequacy and Reliability, the level of potential re-dispatch can be accommodated within the flexible compliance requirements of the rule. Similar conclusions have been reached in recent studies of the potential impact of emission reductions from existing power plants.[131]

The EPA also examined the technical capability of the natural gas supply and delivery system to provide increased quantities of natural gas and the capability of the electricity transmission system to accommodate shifting generation patterns. For several reasons, we conclude that these systems would be capable of supporting the degree of increased NGCC utilization needed for states to achieve the proposed goals. First, the natural gas pipeline system is already supporting national average NGCC utilization rates of 60 percent or higher during peak hours, which are the hours when constraints on pipelines or electricity transmission networks are most likely to arise. NGCC unit utilization rates during the range of peak daytime hours from 10 a.m. to 9 p.m. are typically 15 to 20 percentage points above their average utilization rates (which have recently been in the range of 40 to 50 percent).[132] Fleet-wide combined-cycle average monthly utilization rates have reached 65 percent,[133] showing that the pipeline system can currently support these rates for an extended period. If the current pipeline and transmission systems allow these utilization rates to be achieved in peak hours and for extended periods, it is reasonable to expect that similar utilization rates should also be possible in other hours when constraints are typically less severe, and be reliably sustained for other months of the year. The second consideration supporting our view that natural gas and electricity system

[125] See, e.g., North American Electric Reliability Corp., 2008–2012 Generating Unit Statistical Brochure—All Units Reporting, *http://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx*; Higher Availability of Gas Turbine Combined Cycle, Power Engineering (Feb. 1, 2011), *http://www.power-eng.com/articles/print/volume-115/issue-2/features/higher-availability-of-gas-turbine-combined-cycle.html*.

[126] Today in Energy, EIA (June 6, 2012) (*http://www.eia.gov/todayinenergy/detail.cfm?id=6990*).

[127] The corresponding percentages of NGCC units that in 2012 operated at annual utilization rates of at least 65 percent and at least 75 percent were 16 percent and 6 percent, respectively.

[128] Air Markets Program Data (at *http://ampd.epa.gov/ampd/*).

[129] See Section VII for further explanation of how goals were computed.

[130] For covered sources.

[131] See Greenhouse Gas Emission Reductions From Existing Power Plants: Options to Ensure Electric System Reliability (Analysis Group, Inc., May 2014). Also see the Resource Adequacy Technical Support Document.

[132] EIA, Average utilization of the nation's natural gas combined-cycle power plant fleet is rising, Today in Energy, July 9,2011, *http://www.eia.gov/todayinenergy/detail.cfm?id=1730#*; EIA, Today in Energy, Jan. 15, 2014, *http://www.eia.gov/todayinenergy/detail.cfm?id=14611* (for recent data).

[133] EIA, Electric Power Monthly, February, 2014. Table 6.7.A.

infrastructure would be capable of supporting increased NGCC unit utilization rates is the flexibility of the emission guidelines. The state goals do not require any particular NGCC unit utilization rate to be achieved in any hour or year of the initial plan period. Thus, even if isolated natural gas or electricity system constraints were to limit NGCC unit utilization rates in certain locations in certain hours, this would not prevent an increase in NGCC generation overall across a state or broader region and across all hours. The third consideration supporting a conclusion regarding the adequacy of the infrastructure is that pipeline and transmission planners have repeatedly demonstrated the ability to methodically relieve bottlenecks and expand capacity.[134] Natural gas pipeline capacity has regularly been added in response to increased gas demand and supply, such as the addition of large amounts of new NGCC capacity from 2001 to 2003, or the delivery to market of unconventional gas supplies since 2008. These pipeline capacity increases have added significant deliverability to the natural gas pipeline network to meet the potential demands from increased use of existing NGCC units. Over a longer time period, much more significant pipeline expansion is possible. In previous studies, when the pipeline system was expected to face very large demands for natural gas use by electric utilities about ten years ago, increases of up to 30 percent in total deliverability out of the pipeline system were judged to be possible by the pipeline industry.[135] There have been notable pipeline capacity expansions over the past five years, and substantial additional pipeline expansions are currently under construction.[136] Similarly, the electric transmission system is undergoing substantial expansion.[137] Further, as discussed below in Sections VII.D and VIII of this preamble (on state flexibilities and state plans, respectively), we believe the flexible nature of the proposed goals provides time for infrastructure improvements to occur should they prove necessary in some locations.[138] Combining these factors of currently observed average monthly NGCC utilization rates of up to 65 percent, the flexibility of the emission guidelines, and the availability of time to address any existing infrastructure limitations, it is reasonable to conclude that the natural gas pipeline system can reliably deliver sufficient natural gas supplies, and the electric transmission system can reliably accommodate changed generation patterns, to allow NGCC utilization to increase up to an average annual utilization rate of 70 percent.

We recognize that re-dispatch does contemplate an associated increase in natural gas production, consistent with the current trends in the natural gas industry. The EPA expects the growth in NGCC generation assumed in goal-setting to be feasible and consistent with domestic natural supplies. Increases in the natural gas resource base have led to fundamental changes in the outlook for natural gas. There is general agreement that recoverable natural gas resources will be substantially higher for the foreseeable future than previously anticipated, exerting downward pressure on natural gas prices. According to EIA, proven natural gas reserves have doubled between 2000 and 2012. Domestic production has increased by 32 percent over that same timeframe (from 19.2 TCF in 2000 to 25.3 TCF in 2012). EIA's Annual Energy Outlook for 2014 projects that production will further increase to 29.1 TCF, as a result of increased supplies and favorable market conditions. For comparison, NGCC generation growth of 450 TWh (calculated in goal setting) would result in increased gas consumption of roughly 3.5 TCF for the electricity sector, which is less than the projected increase in natural gas production.

The EPA notes that the assessments described above regarding the ability of the electricity and natural gas industries to achieve the levels of performance indicated for building block 2 in the state goal computations are supported by analysis that has been conducted using the Integrated Planning Model (IPM). IPM is a multi-regional, dynamic, deterministic linear programming model of the U.S. electric power sector that the EPA has used for over two decades to evaluate the economic and emission impacts of prospective environmental policies. To fulfill its purpose of producing projections related to the electric power sector and its related markets—including least-cost capacity expansion and electricity dispatch projections—that reflect industry conditions in as realistic a manner as possible, IPM incorporates representations of constraints related to fuel supply, transmission, and unit dispatch. The model includes a detailed representation of the natural gas pipeline network and the capability to project economic expansion of the network based on pipeline load factors. At the EGU level, IPM includes detailed representations of key operational limitations such as turn-down constraints, which are designed to account for the cycling capabilities of EGUs to ensure that the model properly reflects the distinct operating characteristics of peaking, cycling, and base load units.

As described in more detail below, the EPA used IPM to assess the costs of requiring increasing levels of re-dispatch from higher- to lower-emitting EGUs, and to that end, the EPA developed a series of modeling scenarios that explored shifting generation from existing coal-fired EGUs to existing NGCC units on a 1:1 basis within defined areas.[139] By the nature of IPM's design, those scenarios necessarily also require compliance with the constraints just described (as implemented for any specific scenario). IPM was able to arrive at a solution for scenarios reflecting average NGCC utilization rates of 65, 70, and 75 percent, while observing the market, technical, and regulatory constraints embedded in the model. Such a result is consistent with the EPA's determination that increasing the utilization rates of existing NGCC units to 70 percent, not in every individual instance but on average, as part of a comprehensive approach to reducing CO_2 emissions from existing high carbon-intensity EGUs, would be technically feasible.

c. Cost of Re-Dispatch

Having established the technical feasibility and quantification of replacing incremental generation at

[134] See, e.g., EIA, Natural Gas Pipeline Additions in 2011, Today in Energy; INGAA Foundation, Pipeline and Storage Infrastructure Requirements for a 30 Tcf Market (2004 update); INGAA Foundation, North American Midstream Infrastructure Through 2035—A Secure Energy Future Report (2011).

[135] Pipeline and Storage Infrastructure Requirements for a 30 Tcf Market, INGAA Foundation, 1999 (Updated July, 2004); U.S. gas groups confident of 30-tcf market, Oil and Gas Journal, 1999.

[136] For example, between 2010 and April 2014, 118 pipeline projects with 44,107 MMcf/day of capacity (4,699 miles of pipe) were placed in service, and between April 2014 and 2016 an additional 47 pipeline projects with 20,505 MMcf/day of capacity (1,567 miles of pipe) are scheduled for completion. Energy Information Administration, *http://www.eia.gov/naturalgas/data.cfm*.

[137] According to the Edison Electric Institute, member companies are planning over 170 projects through 2024, with costs totaling approximately $60.6 billion (this is only a portion of the total transmission investment anticipated). Approximately 75 percent of the reported projects (over 13,000 line miles) are high voltage (345 kV and higher). *http://www.eei.org/issuesandpolicy/transmission/Documents/Trans_Project_lowres_bookmarked.pdf*.

[138] See Section VII.D and Section VIII below for discussion of timing flexibility.

[139] See Chapter 3 of the Regulatory Impact Analysis for more detail.

higher-emitting EGUs with generation at NGCC facilities as a CO_2 emissions reduction strategy, we next turn to the question of cost. The cost of the power sector CO_2 emission reductions that can be achieved through re-dispatch among existing fossil fuel-fired EGUs depends on the relative variable costs of electricity production at EGUs with different degrees of carbon intensity. These variable costs are driven by the EGUs' respective fuel costs and by the efficiencies with which they can convert fuel to electricity (i.e., their heat rates). Historically, natural gas has had a higher cost per unit of energy content (e.g., MMBtu) than coal in most locations, but for NGCC units this disadvantage in fuel cost per MMBtu relative to coal-fired EGUs is typically offset in significant part, and sometimes completely, by a heat rate advantage.

The EPA has conducted two sets of extensive analyses to help inform the development of the state-specific emission goals described in this proposal, including analyses of the opportunity to reduce CO_2 emissions through re-dispatch. The first set was a dispatch-only set that provided a framework for understanding the broader economic and emissions implications of shifting generation to NGCC units from more carbon-intensive EGUs without consideration of emission reduction measures reflected in the other building blocks. The second set included additional refinements and more closely reflected all the characteristics of the proposed goals that were used as the basis for assessing the costs and benefits of the overall proposal.[140] Both sets of analyses were conducted using IPM.

The first set—the dispatch-only analyses—explored the magnitude and cost of potential opportunities to shift generation from existing coal-fired EGUs to existing NGCC units within defined areas. The purpose of analyzing these scenarios was to understand and demonstrate to what extent existing NGCC units could increase their dispatch at reasonable costs and without significant impacts on other economic variables such as the prices of natural gas and electricity. To evaluate how EGU owners and grid operators could respond to a state plan's possible requirements, signals, or incentives to re-dispatch from more carbon-intensive to less carbon-intensive EGUs, the EPA analyzed a series of scenarios in which the fleet of NGCC units nationwide was required, on average, to achieve a specified annual utilization rate.[141] Specifically, the scenarios required average NGCC unit utilization rates of at least 65, 70, and 75 percent, respectively. For each scenario, we identified the set of dispatch decisions that would meet electricity demand at the lowest total cost, subject to all other specified operating and reliability constraints for the scenario, including the specified average NGCC unit utilization rate. Further, we allowed re-dispatch to occur exclusively within a region's existing fleet.[142]

The costs and economic impacts of the various scenarios were evaluated by comparing the total costs and emissions from each scenario to the costs and emissions from a business-as-usual scenario. For the scenario reflecting a 70 percent NGCC utilization rate, comparison to the business-as-usual case indicates that the average cost of the CO_2 reductions achieved over the 2020–2029 period was $30 per metric ton of CO_2.[143] We view these estimated costs as reasonable and therefore as supporting the use of a 70 percent utilization rate target for purposes of quantifying the emission reductions achievable at a reasonable cost through the application of the BSER.

However, we also note that the costs just described are higher than we would expect to actually occur in real-world compliance with this proposal's goals. One reason for this is that the 70 percent utilization rate in the scenario exaggerates the stringency with which building block 2 is actually reflected in each of the state goals: While the goal computation procedure uses 70 percent as a target NGCC utilization rate for all states, for only 29 states do the goals actually reflect reaching that target NGCC utilization, with the result that the average NGCC utilization rate reflected in the computed state goals is only 64 percent.[144] Also, at least some states may be able to achieve additional emission reductions through other components of the BSER, and those other components may be relatively inexpensive. The dispatch-only analyses were focused on evaluating the potential impacts of re-dispatch in particular, and as a result, they reflect an assumption that even in a state where re-dispatch might be relatively expensive compared to other available CO_2 emission reduction measures that are part of the BSER, the state plan would rely on re-dispatch to the same extent as the plans of other states. In practice, under these circumstances, states would have flexibility to choose among alternative CO_2 reduction strategies that were part of the BSER, instead of relying on re-dispatch to the maximum extent.

The EPA also analyzed dispatch-only scenarios where shifting of generation among EGUs was limited by state boundaries. In these scenarios with less re-dispatch flexibility, the cost of achieving the quantity of CO_2 reductions corresponding to a nationwide average NGCC unit utilization of 70 percent was $33 per metric ton. Combining the results of the modeling with the factors likely to be present in the real world reinforces the support we expressed above for the 70 percent utilization rate. We remain concerned, however, that higher NGCC utilization rates could be harder to sustain and could exert further upward pressure on prices.

We invite comment on whether the regional or state scenarios should be given greater weight in establishing the appropriate degree of re-dispatch to incorporate into the state goals for CO_2 emission reductions, and in assessing costs.

We also conclude from our analyses that the extent of re-dispatch estimated in this building block can be achieved without causing significant economic impacts. For example, in both of the 70 percent NGCC unit utilization rate scenarios—with re-dispatch limited to regional and state boundaries, respectively—delivered natural gas prices were projected to increase by an average of no more than ten percent over the 2020–2029 period, which is well within the range of historical natural gas price variability.[145] Projected wholesale electricity price increases over the same period were less than seven percent in both cases, which similarly is well within the range of historical electric price variability.[146]

[140] See Regulatory Impact Analysis for more detail.

[141] The utilization rate constraint applied on average to all NGCC units nationwide and did not apply to individual NGCC units or to the fleets of NGCC units within individual states.

[142] To best reflect the integrated nature of the electric power sector, the EPA defined six regions for this analysis, the borders of which are informed by North American Electric Reliability (NERC) regions and Regional Transmission Organizations (RTOs). See Chapter 3 of the Regulatory Impact Analysis for more detail.

[143] The analogous costs for the scenarios with 65 and 75 percent NGCC utilization rates were $21 and $40 per metric ton of CO_2, respectively. For further detail on cost methodology, data inputs, and results, refer to Chapter 3 of the GHG Abatement Measures TSD.

[144] For further explanation of the state goal computation methodology, see Section VII of the preamble and the Goal Computation TSD.

[145] According to EIA data, year-to-year changes in natural gas prices at Henry Hub averaged 29.9 percent over the period from 2000 to 2013. *http://www.eia.gov/dnav/ng/hist/rngwhhdA.htm.*

[146] For example, year-on-year changes in PJM wholesale electricity prices averaged 19.5 percent

Continued

We view these projected impacts as not unreasonable and as supporting use of a 70 percent NGCC utilization rate target for purposes of quantifying the emission reductions achievable through application of the BSER.

However, for the same reasons discussed above with respect to estimated costs per ton of CO_2, in actual implementation we again expect that the economic impacts shown in these scenarios, including natural gas price impacts, are likely overstated compared to the impacts that would actually occur in real-world compliance with this rule's proposed goals. Consistent with this expectation, the comprehensive analyses used to assess the compliance costs and benefits of this proposal, which reflect a more complete representation of the additional flexibility available to states, show significantly smaller economic impacts. These analyses are discussed in Section X below.

Based on the analyses summarized above, the EPA proposes that for purposes of establishing state goals, a reasonable estimate regarding the degree of mass emission reductions achievable at fossil fuel-fired steam EGUs can be determined based on the degree to which electricity generation could be shifted from more carbon-intensive EGUs to less carbon-intensive EGUs within the state at reasonable cost through re-dispatch. The increment of emission reductions incorporated in this component of our proposed BSER determination is commensurate with an annual utilization rate for the state's NGCC units of up to 70 percent, on average across all the NGCC units in the state.

For purposes of the alternative set of goals on which we are seeking comment, we have used the less stringent target of a 65 percent average utilization rate for NGCC units. In 2012, approximately 16 percent of existing NGCC plants larger than 25 megawatts had utilization rates equal to or higher than this level. Also, as noted earlier, average NGCC utilization nationwide is already over 60 percent in some peak hours. We therefore view 65 percent as a reasonable lower-bound estimate of an achievable average NGCC utilization rate, and we would expect the costs and economic impacts from re-dispatch associated with a 65 percent NGCC utilization target to be lower than the costs and impacts associated with the 70 percent utilization target. Our cost analysis indicated that CO_2 emission reductions consistent with a 65 percent average NGCC utilization rate could be achieved at a cost of $21 per metric ton.

As discussed above, in addition to analyzing the impacts of using the proposed 70 percent target utilization rate for existing NGCC units, the EPA has also performed preliminary analysis of the impacts of using a target utilization rate for existing NGCC units of 75 percent. That analysis showed that CO_2 emission reductions consistent with a 75 percent target utilization rate could be achieved at a cost of $40 per metric ton.[147] We invite comment on whether we should consider options for a target utilization rate for existing NGCC units greater than the proposed 70 percent target utilization rate.

We invite comment on these proposed findings and on all other issues raised by the discussion above and the related portions of the Greenhouse Gas Abatement Measures TSD.

3. Building Block 3—Using an Expanded Amount of Less Carbon-Intensive Generating Capacity

The third element of the foundation for the EPA's BSER determination for reducing CO_2 emissions at affected fossil fuel-fired EGUs also goes to the achievement of reductions in mass emissions, but in this case the reductions would occur at all affected EGUs, and entails an analysis of the extent to which generation at the affected EGUs can be replaced by using an expanded amount of lower-carbon generating capacity to produce replacement generation. Below we discuss two types of generating capacity that can play this role: Renewable generating capacity and new and preserved nuclear capacity.

a. Renewable Generating Capacity

Renewable electricity (RE) generating technologies are a well-established part of the U.S. power sector. In 2012, electricity generated from renewable technologies, including conventional hydropower, represented 12 percent of total U.S. electricity generation, up from 9 percent in 2005. More than half the states have established renewable portfolio standards (RPS) that require minimum proportions of electricity sales to be supplied with generation from renewable generating resources.[148] Production of this renewable generation replaces predominantly fossil fuel-fired generation and thereby avoids the CO_2 emissions from that replaced generation. The EPA believes that renewable electricity generation is a proven way to assure reductions of CO_2 emissions at affected EGUs at a reasonable cost.[149]

1. Proposed Quantification of Renewable Energy Generation

To estimate the CO_2 emission reductions from affected EGUs achievable based on increases in renewable generation, the EPA has developed a ''best practices'' scenario for renewable energy generation based on the RPS requirements already established by a majority of states. The EPA views the existing RPS requirements as a reasonable foundation upon which to develop such a scenario for two principal reasons. First, in establishing the requirements, states have already had the opportunity to assess those requirements against a range of policy objectives including both feasibility and costs. These prior state assessments therefore support the feasibility and cost of the best practices scenario as well. Second, renewable resource development potential varies by region, and the RPS requirements developed by the states necessarily reflect consideration of the states' own respective regional contexts.[150]

The EPA has not assumed any specific type of renewable generating technology for the best practices scenario. Also, the scenario is not an EPA forecast of renewable capacity development and neither establishes RPS requirements that any state must meet nor makes any determinations regarding allowable RE compliance measures. Rather, it represents a level of renewable resource development for individual states—with recognition of regional differences—that we view as reasonable and consistent with policies that a majority of states have already adopted based on their own policy objectives and assessments of feasibility and cost.

As noted above, renewable resource potential varies regionally. This geographic pattern is reflected in the existing RPS requirements of the various states. Recognizing this pattern, the EPA has grouped the states into six regions for purposes of developing the best

over the period from 2000 to 2013. Ventyx Velocity Suite, ISO real-time data for all hours. Price variability for other eastern ISO regions (NYISO, ISO–NE., and Midcontinent ISO) was similar. Id.

[147] For further analysis related to the use of a 75 percent target utilization rate for NGCC units, see chapter 3 of the GHG Abatement Measures TSD.

[148] Database of State Incentives for Renewables & Efficiency (DSIRE), *http://www.dsireusa.org/summarymaps/index.cfm?ee=0&RE=0.*

[149] For discussion of how states and sources might use RE in state plans, see Section VIII below.

[150] The EPA recognizes that individual RPS policies vary in their specification of where qualifying RE generation must occur. However, the EPA believes the regional structure of this estimation exercise supports a broad interpretation of RPS requirements across states within a region as a proxy for reasonable-cost RE generation potential within the same region.

practices scenario.[151] By comparing each state to a set of neighbors rather than to a single national standard, we are able to take regional variation into account while still maintaining a level of rigor for the scenario's targets. The regional structure is informed by North American Electric Reliability Corporation (NERC) regions and Regional Transmission Organizations (RTOs), with adjustments to align regional borders with state borders and to group Florida and Texas with neighboring states.[152] This structure accounts for similar power system characteristics as well as geographic similarities in RE potential. The grouping of states into the six regions is shown in Table 5 below.

TABLE 5—REGIONS FOR DEVELOPMENT OF BEST PRACTICES RPS SCENARIO

Region	States
East Central	Delaware, District of Columbia*, Maryland, New Jersey, Ohio, Pennsylvania, Virginia, West Virginia.
North Central	Illinois, Indiana, Iowa, Michigan, Minnesota, Missouri, North Dakota, South Dakota, Wisconsin.
Northeast	Connecticut, Maine, Massachusetts, New Hampshire, New York, Rhode Island, Vermont*.
South Central	Arkansas, Kansas, Louisiana, Nebraska, Oklahoma, Texas.
Southeast	Alabama, Florida, Georgia, Kentucky, Mississippi, North Carolina, South Carolina, Tennessee.
West	Arizona, California, Colorado, Idaho, Montana, Nevada, New Mexico, Oregon, Utah, Washington, Wyoming.

* Because Vermont and the District of Columbia lack affected sources, no goals are being proposed for these jurisdictions.

The best practices scenario for each state consists of increasing annual levels of RE generation estimated based on application of an annual RE growth factor to the state's historical RE generation, subject to a maximum RE generation target. The annual RE growth factors and maximum RE generation targets were developed separately for each of the six regions. Our procedure for determining these elements is described in the Greenhouse Gas Abatement Measures TSD and summarized below.

The EPA first quantified the amount of renewable generation in 2012 in each state. The EPA then summed these amounts for all states in each region to determine a regional starting level of renewable generation prior to implementation of the best practices scenario. Hydropower generation is excluded from this existing 2012 generation for purposes of quantifying BSER-related RE generation potential because building the methodology from a baseline that includes large amounts of existing hydropower generation could distort regional targets that are later applied to states lacking that existing hydropower capacity. The exclusion of pre-existing hydropower generation from the baseline of this target-setting framework does not prevent states from considering incremental hydropower generation from existing facilities (or later-built facilities) as an option for compliance with state goals.

Next, the EPA estimated the aggregate target level of RE generation in each of the six regions assuming that all states within each region can achieve the RE performance represented by an average of RPS requirements in states within that region that have adopted such requirements. For this purpose, the EPA averaged the existing RPS percentage requirements that will be applicable in 2020 and multiplied that average percentage by the total 2012 generation for the region. We also computed each state's maximum RE generation target in the best practices scenario as its own 2012 generation multiplied by that average percentage. (For some states that already have RPS requirements in place, these amounts are less than their RPS targets for 2030.)

For each region we then computed the regional growth factor necessary to increase regional RE generation from the regional starting level to the regional target through investment in new RE capacity, assuming that the new investment begins in 2017, the year following the initial state plan submission deadline,[153] and continues through 2029. This regional growth factor is the growth factor used for each state in that region to develop the best practices scenario.

Finally, we developed the annual RE generation levels for each state. To do this, we applied the appropriate regional growth factor to that state's initial RE generation level, starting in 2017, but stopping at the point when additional growth would cause total RE generation for the state to exceed the state's maximum RE generation target. For computation of the proposed state goals discussed in Section VII.C below, we used the annual amounts for the years 2020 through 2029. For computation of the alternate state goals discussed in Section VII.E below, on which we are seeking comment, we used the annual amounts for the years 2020 through 2024.

Alaska and Hawaii are treated as separate regions. Their RE targets are based on the lowest regional RE target among the continental U.S. regions and their growth factors are based upon historical growth rates in their own RE generation. We invite comment regarding the treatment of Alaska and Hawaii as part of this method.

For details on the regional targets and growth factors applied, please refer to Chapter 4 of the GHG Abatement Measures TSD.

The cumulative RE amounts for each state, represented as percentages of total generation, are shown in Table 6.

[151] Given their unique locations, Alaska and Hawaii are not grouped with other states into these regions. As a conservative approach to estimating RE generation potential in Alaska and Hawaii, the EPA has developed RE generation targets for each of those states based on the lowest values for the six regions evaluated here.

[152] The regions are the same as those used in regional modeling of this rule; see the Regulatory Impact Analysis for more information on the regional modeling.

[153] See Section VIII below for further discussion of timing requirements for state plan submittals.

TABLE 6—STATE RE GENERATION LEVELS FOR STATE GOAL DEVELOPMENT

[Percentage of annual generation][154]

State	2012 percent)	Proposed goals		Alternate goals	
		Interim level * (percent)	Final level (percent)	Interim level * (percent)	Final level (percent)
Alabama	2	6	9	4	5
Alaska	1	2	2	1	1
Arizona	2	3	4	3	3
Arkansas	3	5	7	4	5
California	15	20	21	20	21
Colorado	12	19	21	17	19
Connecticut	2	5	9	4	5
Delaware	2	7	12	4	5
Florida	2	6	10	4	6
Georgia	3	8	10	6	7
Hawaii	9	10	10	10	10
Idaho	16	21	21	21	21
Illinois	4	7	9	6	7
Indiana	3	5	7	4	5
Iowa	25	15	15	15	15
Kansas	12	19	20	19	20
Kentucky	0	1	2	1	1
Louisiana	2	5	7	4	4
Maine	28	25	25	25	25
Maryland	2	10	16	6	8
Massachusetts	5	15	24	11	13
Michigan	3	6	7	5	6
Minnesota	18	15	15	15	15
Mississippi	3	8	10	6	8
Missouri	1	2	3	2	2
Montana	5	8	10	6	7
Nebraska	4	8	11	6	7
Nevada	8	14	18	12	14
New Hampshire	7	19	25	15	19
New Jersey	2	8	16	5	7
New Mexico	11	18	21	16	18
New York	4	11	18	8	10
North Carolina	2	7	10	5	6
North Dakota	15	15	15	15	15
Ohio	1	6	11	4	5
Oklahoma	11	19	20	18	20
Oregon	12	19	21	17	19
Pennsylvania	2	9	16	5	7
Rhode Island	1	4	6	3	3
South Carolina	2	7	10	5	6
South Dakota	24	15	15	15	15
Tennessee	1	3	6	2	3
Texas	8	16	20	13	15
Utah	3	5	7	4	5
Virginia	3	12	16	9	12
Washington	7	12	15	10	11
West Virginia	2	8	14	5	6
Wisconsin	5	8	11	7	8
Wyoming	9	15	19	13	14

The EPA notes that for some states, the RE generation targets developed using the proposed approach are less than those states' reported RE generation amounts for 2012. We invite comment on whether the approach for quantifying the RE generation component of each state's goal should be modified to include a floor based on reported 2012 RE generation in that state.

This approach to quantification of a state's RE generation target does not explicitly account for the amount of fossil fuel-fired generation in that state. Without such an accounting, the application of this approach could yield, for a given state, an increase in RE generation that exceeds the state's reported 2012 fossil fuel-fired generation.[155] The EPA invites comment on whether this approach should be modified so that the difference between a state's RE generation target and its 2012 level of corresponding RE generation does not exceed the state's

[154] Vermont and the District of Columbia are excluded from this table because we are not proposing goals for those jurisdictions.

[155] In this proposed RE approach, this situation only occurs with the RE targets quantified for the state of Washington.

reported 2012 fossil fuel-fired generation.[156]

We note that with the exception of hydropower, the RE generation levels represent total amounts of RE generation, rather than incremental amounts above a particular baseline level. As a result, this RE generation can be supplied by any RE capacity regardless of its date of installation. This approach is therefore focused on quantifying the fulfillment of each state's potential for the deployment of RE as part of BSER using a methodology that does not require discriminating between RE capacity that was installed before or after any given date. Under this approach, states in a given region where a higher proportion of total generation has already been achieved from renewable resources are assumed to have less opportunity for deployment of additional renewable generation as part of the BSER framework informing state goals, in comparison to states in that region where the proportion of total generation achieved from renewable resources to date has been lower. That being said, the assumptions of RE generation used to develop the state goals do not impose any specific RE generation requirements on any state; they are only used to inform the quantification of state goals to which states may respond with whatever emission reduction measures are preferred.

With regard to hydropower, we seek comment regarding whether to include 2012 hydropower generation from each state in that state's ''best practices'' RE quantified under this approach, and whether and how the EPA should consider year-to-year variability in hydropower generation if such generation is included in the RE targets quantified as part of BSER. Chapter 4 of the GHG Abatement Measures TSD presents state RE targets both with and without the inclusion of each state's 2012 hydropower generation.

2. Cost of CO_2 Emission Reductions From RE Generation

The EPA believes that RE generation at the levels represented in the best practices scenario can be achieved at reasonable costs. According to an EPA analysis based on EIA levelized costs, the cost to reduce emissions through RE ranges from $10 to $40 per metric ton of CO_2.[157] Analysis of RE development in response to state RPS policies also finds historical and projected costs of RPS-driven RE deployment to be modest. One comparative analysis that ''synthesize[d] and analyze[d] the results and methodologies of 28 distinct state or utility-level RPS cost impact analyses'' projected the median change in retail electricity price to be $0.0004 per kilowatt-hour (a 0.7 percent increase), the median monthly bill impact to be between $0.13 and $0.82, and the median CO_2 reduction cost to be $3 per metric ton.[158] This finding has been confirmed with more recent RPS cost data, including a report that determined 2010–2012 retail electricity price impacts due to state RPS policies to be less than two percent, with only two states experiencing price impacts of greater than three percent.[159] Additionally, the National Renewable Energy Laboratory has projected low incremental costs for a range of scenarios reflecting significant increases in RE penetration, including scenarios that increase RE penetration to a range of 30 to 40 percent of national generation, levels higher than those projected in our best practices scenario.[160]

While RPS requirements will continue to grow over time, the EPA does not expect this anticipated expansion to fall outside the historical norms of deployment or to create unusual pressure for cost increases. Full compliance with current RPS goals through 2035 would require approximately 4 to 4.5 GW of new renewable capacity per year. Average deployment of RPS-supported renewable capacity from 2007 to 2012 exceeded 6 GW per year.[161] In addition, recent improvements in RPS compliance rates indicate to the EPA the reasonableness of current RPS growth trajectories. Weighted average compliance rates among all states have improved in each of the past three reported years (2008–2011) from 92.1 percent to 95.2 percent despite a 40 percent increase in RPS obligations during this period.[162]

We invite comment on this approach to treatment of renewable generating capacity as a basis for the best system of emission reduction adequately demonstrated and for quantification of state goals.

3. Alternative Approach to Quantification of RE Generation

Additionally, the EPA is soliciting comment on an alternative approach to quantification of renewable generation to support the BSER. Unlike the proposed RE scenario described above that relies on a regional application of state RPS commitments, the alternative methodology relies on a state-by-state assessment of RE technical and market potential. The alternative approach is based on two sources of information: A metric representing the degree to which the technical potential of states to develop RE generation has already been realized, and IPM modeling of RE deployment at the state level under a scenario that reflects a reduced cost of building new renewable generating capacity.

The metric measuring realization of RE technical potential in a state compares each state's existing renewable generation by technology type with the technical potential for that technology in that state as assessed by the National Renewable Energy Laboratory (NREL).[163] This comparison yields, for each state and for each RE technology, a proportion of renewable generation technical potential that has been achieved and can be represented as an RE development rate. For example, if

[156] For example, for the state of Washington the proposed approach yields a final RE generation target of 17.7 TWh, representing an increase of 9.5 TWh over Washington's reported 2012 RE generation (excluding hydropower) of 8.2 TWh. By comparison, Washington's 2012 reported fossil fuel-fired generation was 9.4 TWh. (The 2012 reported RE and fossil fuel-fired generation amounts for all states are included in the Goal Computation TSD.) If the limitation described in the text were applied to Washington, the state's incremental quantified RE generation would be limited to 9.4 TWh, with the result that the state's final RE generation target would be 17.6 TWh instead of 17.7 TWh.

[157] This analysis is based upon EIA's AEO 2014 Estimated Levelized Costs of Electricity for New Generation Sources, available at *http://www.eia.gov/forecasts/aeo/electricity_generation.cfm.*

[158] Chen et al., ''Weighing the Costs and Benefits of State Renewable Portfolio Standards: A Comparative Analysis of State-Level Policy Impact Projections,'' Lawrence Berkeley National Laboratory, March 2007, available at *http://emp.lbl.gov/publications/weighing-costs-and-benefits-state-renewables-portfolio-standards-comparative-analysis-s.*

[159] Galen Barbose, ''Renewables Portfolio Standards in the United States: A Status Update,'' Lawrence Berkeley National Lab, November 2013. Also to be published in Heeter et al., ''Estimating the Costs and Benefits of Complying with Renewable Portfolio Standards: Reviewing Experience to Date'' [review draft title]. UNPUBLISHED. National Renewable Energy Laboratory and Lawrence Berkeley National Laboratory.

[160] NREL, ''Renewable Electricity Futures Study'', NREL/TP–6A20–52409, 2012, *http://www.nrel.gov/analysis/re_futures/.*

[161] Galen Barbose, ''Renewables Portfolio Standards in the United States: A Status Update,'' Lawrence Berkeley National Laboratory, November 2013.

[162] *http://emp.lbl.gov/rps*, retrieved March 2014. The RPS compliance measure cited is inclusive of credit multipliers and banked RECs utilized for compliance, but excludes alternative compliance payments, borrowed RECs, deferred obligations, and excess compliance. This estimate does not represent official compliance statistics, which vary in methodology by state.

[163] Lopez *et al.,* NREL, ''U.S. Renewable Energy Technical Potentials: A GIS-Based Analysis,'' (July 2012).

a given state has 500 MWh of solar generation in 2012 while NREL assesses that state's solar generation technical potential at 5,000 MWh/year, then that state's solar RE development rate would be ten percent. The EPA then considers the range of RE development rates across states in order to define a benchmark RE development rate for each technology.

While a benchmark RE development rate offers a useful metric to quantify the proportion of RE generation that would bring all states up to a designated proportion of RE generation that has been achieved in practice by certain states to date, such a metric does not explicitly take into account the cost that would be faced to reach the benchmark RE development rate in each state. In order to take this cost into account, for this alternative approach the EPA has paired the benchmark RE development rates described above with IPM modeling of RE deployment at the state level, based on a scenario reflecting a reduced cost of building new renewable generating capacity. The cost reduction for new RE generating capacity is intended to represent the avoided cost of other actions that could be taken instead to reduce CO_2 emissions from the power sector. In the Alternative RE Approach TSD, available in the docket, we show the RE deployment levels modeled using a cost reduction of up to $30 per MWh, a level that is consistent with the cost range of $10 to $40 per metric ton of avoided CO_2 emissions estimated for the proposed RE scenario described above.[164]

Under this alternative RE approach, the EPA would quantify RE generation for each technology in each state as the lesser of (1) that technology's benchmark rate multiplied by the technology's in-state technical potential, or (2) the IPM-modeled market potential for that specific technology. For example, if the benchmark RE development rate for solar generation is determined to be 12 percent, and the hypothetical state described above has a solar generation technical potential of 5,000 MWh/year, then the benchmark RE development level of generation for that state would be 600 MWh/year. If the IPM-modeled market potential for solar generation in that state is 750 MWh/year, then this approach would quantify solar generation for that state as the benchmark RE development level (600 MWh/year) because it is the lesser amount of those two measures.

[164] Additional detail regarding this modeling and approach is provided in the Alternative RE Approach TSD.

Having quantified an amount of RE generation from each RE technology in each state, the EPA would then determine for each state a total level of RE generation that equals the sum of the generation quantified for each of the assessed RE technologies in that state. If the EPA were to adopt this alternative approach for quantifying RE in BSER, these total levels of RE generation for each state would be incorporated in state goals in place of the RE generation levels quantified using the proposed approach described above. Further methodological detail and state-level RE targets for this alternative approach are provided in the Alternative RE Approach TSD in the docket.

We invite comment on this alternative approach to quantification of RE generation to support the BSER. We note that the three specific requests for comment made above with respect to the proposed quantification approach—addressing, first, the possibility of a floor based on 2012 RE generation, second, the possibility of a limitation based on 2012 fossil fuel-fired generation and, third, the treatment of hydropower generation—apply to this alternative approach as well.[165]

Finally, the EPA notes that the alternative RE approach described above is one of a number of possible methodologies for using technical and economic renewable energy potential to quantify RE generation for purposes of state goals. The EPA invites comment on other possible techno-economic approaches. For example, a conceptual framework for another techno-economic approach is provided in the Alternative RE Approach TSD.

b. New and Preserved Nuclear Capacity

Nuclear generating capacity facilitates CO_2 emission reductions at fossil fuel-fired EGUs by providing carbon-free generation that can replace generation at those EGUs. Because of their relatively low variable operating costs, nuclear EGUs that are available to operate typically are dispatched before fossil fuel-fired EGUs. Increasing the amount of nuclear capacity relative to the amount that would otherwise be available to operate is therefore a technically viable approach to support reducing CO_2 emissions from affected fossil fuel-fired EGUs.

[165] The Alternative RE Approach TSD presents the quantification of hydropower generation under the alternative approach, as well as the resulting state RE targets both with and without hydropower generation included.

1. Proposed Quantification of Nuclear Generation

One way to increase the amount of available nuclear capacity is to build new nuclear EGUs. However, in addition to having low variable operating costs, nuclear generating capacity is also relatively expensive to build compared to other types of generating capacity, and little new nuclear capacity has been constructed in the U.S. in recent years; instead, most recent generating capacity additions have consisted of NGCC or renewable capacity. Nevertheless, five nuclear EGUs at three plants are currently under construction: Watts Bar 2 in Tennessee, Vogtle 3–4 in Georgia, and Summer 2–3 in South Carolina. The EPA believes that since the decisions to construct these units were made prior to this proposal, it is reasonable to view the incremental cost associated with the CO_2 emission reductions available from completion of these units as zero for purposes of setting states' CO_2 reduction goals (although the EPA acknowledges that the planning for those units likely included consideration of the possibility of future regulation of CO_2 emissions from EGUs). Completion of these units therefore represents an opportunity to reduce CO_2 emissions from affected fossil fuel-fired EGUs at a very reasonable cost. For this reason, we are proposing that the emission reductions achievable at affected sources based on the generation provided at the identified nuclear units currently under construction should be factored into the state goals for the respective states where these new units are located. However, the EPA also realizes that reflecting completion of these units in the goals has a significant impact on the calculated goals for the states in which these units are located. If one or more of the units were not completed as projected, that could have a significant impact on the state's ability to meet the goal. We therefore take comment on whether it is appropriate to reflect completion of these units in the state goals and on alternative ways of considering these units when setting state goals.

Another way to increase the amount of available nuclear capacity is to preserve existing nuclear EGUs that might otherwise be retired. The EPA is aware of six nuclear EGUs at five plants that have retired or whose retirements have been announced since 2012: San Onofre Units 2–3 in California, Crystal River 3 in Florida, Kewaunee in Wisconsin, Vermont Yankee in Vermont, and Oyster Creek in New Jersey. While each retirement decision is based on the unique circumstances of that individual unit, the EPA recognizes that a host of factors—increasing fixed operation and maintenance costs, relatively low wholesale electricity prices, and additional capital investment associated with ensuring plant security and emergency preparedness—have altered the outlook for the U.S. nuclear fleet in recent years. Reflecting similar concern for these challenges, EIA in its most recent Annual Energy Outlook has projected an additional 5.7 GW of capacity reductions to the nuclear fleet. EIA describes the projected capacity reductions—which are not tied to the projected retirement of any specific unit—as necessary to recognize the ''continued economic challenges'' faced by the higher-cost nuclear units.[166] Likewise, without making any judgment about the likelihood that any individual EGU will retire, we view this 5.7 GW, which comprises an approximately six percent share of nuclear capacity, as a reasonable proxy for the amount of nuclear capacity at risk of retirement.

2. Cost of CO_2 Emission Reductions From Nuclear Generation

We have determined that, based on available information regarding the cost and performance of the nuclear fleet, preserving the operation of at-risk nuclear capacity would likely be capable of achieving CO_2 reductions from affected EGUs at a reasonable cost. For example, retaining the estimated six percent of nuclear capacity that is at risk for retirement could support avoiding 200 to 300 million metric tons of CO_2 over an initial compliance phase-in period of ten years.[167] According to a recent report, nuclear units may be experiencing up to a $6/MWh shortfall in covering their operating costs with electricity sales.[168] Assuming that such a revenue shortfall is representative of the incentive to retire at-risk nuclear capacity, one can estimate the value of offsetting the revenue loss at these at-risk nuclear units to be approximately $12 to $17 per metric ton of CO_2. The EPA views this cost as reasonable. We therefore propose that the emission reductions supported by retaining in operation six percent of each state's historical nuclear capacity should be factored into the state goals for the respective states.[169]

For purposes of goal computation, generation from under-construction and preserved nuclear capacity is based on an estimated 90 percent average utilization rate for U.S. nuclear units, consistent with long-term average annual utilization rates observed across the nuclear fleet. The methodology for taking this generation into account for purposes of setting state emission rate goals is described below in Section VII on state goals and in the Goal Computation TSD.

We invite comment on all aspects of the approach discussed above. In addition, we specifically request comment on whether we should include in the state goals an estimated amount of additional nuclear capacity whose construction is sufficiently likely to merit evaluation for potential inclusion in the goal-setting computation. If so, how should we do so—for example, according to EGU owners' announcements, the issuance of permits, projections of new construction by the EPA or another government agency, or commercial projections? What specific data sources should we consider for those permits or projections?

4. Building Block 4—Demand-Side Energy Efficiency

The fourth element of the foundation for the EPA's BSER determination for reducing CO_2 emissions at affected fossil fuel-fired EGUs also supports reduced mass emissions at all affected EGUs, and entails an analysis of the extent to which generation reductions at the affected EGUs can be supported by reducing the demand for generation at those EGUs through measures that reduce the overall quantity of generation demanded by end-users.[170]

a. Benefits of Demand-Side Energy Efficiency

Reducing demand for generation at affected EGUs through policies to improve demand-side energy efficiency is a proven basis for reducing CO_2 emissions at those EGUs. Every state has established demand-side energy efficiency policies, and many stakeholders emphasized the success of these policies in reducing electricity consumption by large amounts. For example, data reported to the U.S. Energy Information Administration (EIA) show that in 2012 California and Minnesota avoided 12.5 percent and 13.1 percent of their electricity demand, respectively, through their demand-side efficiency programs.[171] Additionally, multiple studies have found that significant improvements in end-use energy efficiency can be realized at less cost than the savings from avoided power system costs.[172] Increased investment in demand-side energy efficiency is being supported by efforts at the federal, state, and local levels of government as well as corporate efforts. Many stakeholders urged the inclusion of demand-side energy efficiency policies as compliance options under the CAA section 111(d) guidelines.

By reducing electricity consumption, energy efficiency avoids greenhouse gas emissions associated with electricity generation. Because fossil fuel-fired EGUs typically have higher variable costs than other EGUs (such as nuclear and renewable EGUs), their generation is typically the first to be replaced when demand is reduced. Consequently, reductions in the utilization of fossil fuel-fired EGUs can be supported by reducing electricity consumption and, by the same token, reductions in electricity consumption avoid the CO_2 emissions associated with the avoided generation. In this manner, in 2011, state demand-side energy efficiency programs are estimated to have reduced CO_2 emissions by 75 million metric tons.[173] And when integrated into a comprehensive approach for addressing CO_2 emissions, demand-side energy efficiency improvements offer even more potential to improve the carbon profile of the electricity supply system. For example, if incentives exist to shift generation to lower carbon-intensity EGUs, and those EGUs are fully utilized, reducing demand can support further reductions in carbon intensity. This potential effect reinforces the appropriateness of incorporating demand-side efficiency improvements into a comprehensive approach to address power sector CO_2 emissions. In addition, by supporting reductions in fossil fuel usage at EGUs, demand-side

[166] Jeffrey Jones and Michael Leff, EIA, ''Implications of accelerated power plant retirements,'' (April 2014).

[167] Assuming replacement power for at-risk nuclear capacity is sourced from new NGCC capacity at 800 lbs/MWh or the power system at 1127 lbs CO_2/MWh (average 2020 power sector emissions intensity as projected in the EPA's IPM Base Case).

[168] ''Nuclear * * * The Middle Age Dilemma?'' Eggers, et al., Credit Suisse, February 2013.

[169] A state's historical nuclear fleet is defined as all units in commercial operation as of May 2014 with no current plans to retire.

[170] Electricity end-users and electricity end-use referred to throughout this subsection include the residential, commercial and industrial sectors.

[171] Energy Information Administration Form 861, 2012, available at *http://www.eia.gov/electricity/data/eia861/*.

[172] See, e.g., Electric Power Research Institute, U.S. Energy Efficiency Potential Through 2035 (Final Report, April 2014); Wang, Yu and Marilyn A. Brown, Policy Drivers for Improving Electricity End-Use Efficiency in the U.S.: An Economic-Engineering Analysis (Energy Efficiency, 2014).

[173] Innovation, Electricity, Efficiency (an Institute of the Edison Foundation), Summary of Customer-Funded Electric Efficiency Savings, Expenditures, and Budgets (2011–2012) (March 2013), available at *http://www.edisonfoundation.net/iei/ourwork/Pages/issuebriefs.aspx*.

energy efficiency supports not only reduced CO_2 emissions and carbon intensity of the power sector, but also reduced criteria pollutant emissions, cooling water intake and discharge, and solid waste production associated with fossil fuel combustion. By reducing electricity usage significantly, energy efficiency also commonly reduces the bills of electricity customers.

b. ''Best Practices'' for Demand-Side Energy Efficiency

To estimate the potential CO_2 reductions at affected EGUs that could be supported by implementation of demand-side energy efficiency policies as a part of state goals, the EPA developed a ''best practices'' demand-side energy efficiency scenario. This scenario provides an estimate of the potential for sources and states to implement policies that increase investment in demand-side energy efficiency technologies and practices at reasonable costs. It does not represent an EPA forecast of business-as-usual impacts of state energy efficiency policies or an EPA estimate of the full potential of end-use energy efficiency available to the power system, but rather represents a feasible policy scenario showing the reductions in fossil fuel-fired electricity generation resulting from accelerated use of energy efficiency policies in all states consistent with a level of performance that has already been achieved or required by policies (e.g., energy efficiency resource standards) of the leading states. The data and methodology used to develop the best practices scenario are summarized below.

We have not assumed any particular type of demand-side energy efficiency policy. States with leading energy efficiency performance have employed a variety of strategies that are implemented by a range of entities including investor-owned, municipal and cooperative electric utilities as well as state agencies and third-party administrators. These include energy efficiency programs,[174] building energy codes, state appliance standards (for appliances without federal standards), tax credits, and benchmarking requirements for building energy use.[175] Energy efficiency policies are designed to accelerate the deployment of demand-side energy efficiency technologies, practices, and measures by addressing market barriers and market failures that limit their adoption. Some states have adopted energy efficiency resource standards[176] (EERS) to drive investment in energy efficiency programs; some have relied on other strategies; most states are using multiple policy approaches. Based on historical data on energy efficiency program savings and analysis of the requirements of existing state energy efficiency policies, twelve leading states have either achieved—or have established requirements that will lead them to achieve—annual incremental savings rates of at least 1.5 percent of the electricity demand that would otherwise have occurred.[177] The 1.5 percent savings rate is inclusive of, not additional to, existing state energy efficiency requirements. These savings levels are realized exclusively through the adoption and implementation of energy efficiency programs. The energy savings data underpinning these analyses are derived from energy efficiency program reports required by state public utility commissions and other entities with a similar oversight role.[178] These state commissions define and oversee the analysis and reporting requirements for energy efficiency programs as part of their role of overseeing rates for utility customers in their states. One typical requirement is the application of recognized evaluation, measurement, and validation (EM&V) protocols that specify industry-preferred approaches and methodologies for estimating savings from efficiency programs.[179]

While EM&V data reflect documented electricity savings from energy efficiency programs, they typically do not account for potential electricity savings available from additional state-implemented policies for which EM&V protocols are less consistently required or applied, such as building energy codes. Thus, we consider the 1.5 percent annual incremental savings[180] rate to be a reasonable estimate of the energy efficiency policy performance that is already achieved or required by leading states and that can be achieved at reasonable costs by all states given adequate time. If we were to capture the potential for additional policies, such as the adoption and enforcement of state or local building energy codes, to contribute additional reductions in electricity demand beyond those resulting from energy efficiency programs, we could reasonably increase the targeted annual incremental savings rate beyond 1.5 percent.

For states where EE program experience is more limited, reaching a best-practices level of performance requires undertaking a set of activities that takes some time to plan, implement, and evaluate. For the best practices scenario, we have therefore estimated that each state's annual incremental savings rate increases from its 2012 annual saving rate[181] to a rate of 1.5 percent over a period of years starting in 2017. (Thus, the goal for each state differs to reflect the assumption that in a state already close to a 1.5 percent annual incremental savings rate, energy efficiency programs can be expanded to reach that rate sooner than in a state that is further from that rate.) The pace at which states are estimated to increase their savings rate level is 0.2 percent per year. This rate is consistent with past performance and future requirements of leading states.[182] For states already at or above the 1.5 percent

[174] Energy efficiency programs are driven by a variety of state policies including energy efficiency resource standards, requirements to acquire all cost-effective energy efficiency, integrated resource planning requirements, and demand-side management plans and budgets. Funding for energy efficiency programs is provided through a variety of mechanisms as well, including per kilowatt-hour surcharges and proceeds from forward capacity market and emission allowance auctions. The programs are implemented by a range of entities including investor-owned, municipal, and cooperative electric utilities, state agencies, and designated third-party administrators. All end-use sectors (residential, commercial, and industrial) are targeted by energy efficiency programs and numerous strategies are employed, including targeted rebates for high-efficiency appliances; energy audits with recommendations for cost-effective, energy-saving upgrades; and processes to certify energy efficiency service providers.

[175] See the appendix to the State Plan Considerations TSD for descriptions of the full array of demand-side energy efficiency policies currently employed by states.

[176] EERS establish specific, long-term targets for energy savings that utilities or non-utility program administrators must meet through customer energy efficiency programs. EERS, as well as requirements that utilities acquire all cost-effective energy efficiency, have been the most impactful state energy efficiency strategies in recent years.

[177] The historical data used are reported to the Energy Information Administration through Form EIA–861. The analysis and summary of state energy efficiency policies is from the American Council for an Energy-Efficient Economy (ACEEE), State EERS Activity Policy Brief (February 24, 2014). See the Greenhouse Gas Abatement Measures TSD for more information.

[178] E.g., energy efficiency programs operated by municipal and cooperative utilities may report their program results to their Boards of Directors rather than to a state utility commission.

[179] See the EM&V section of the State Plan TSD for more information on EE program evaluation.

[180] This incremental savings rate and all others discussed in this subsection represent net, rather than gross, energy savings. Gross savings are the changes in energy use (MWh) that result directly from program-related actions taken by program participants, regardless of why they participated in a program. Net savings refer to the changes in energy use that are directly attributable to a particular energy efficiency program after accounting for free-ridership, spillover, and other factors.

[181] 2012 is the most recent year for energy efficiency program incremental savings data reported using EIA Form 861.

[182] See the Greenhouse Gas Abatement Measures TSD for more information.

annual incremental savings rate (based on 2012 reported data), we estimate that they would realize a 1.5 percent rate in 2017 and maintain that rate through 2029. For all states we assume the initial savings rate (the lower of their 2012 value or 1.5 percent) is realized in 2017 and increases each year by 0.2 percent until the target rate of 1.5 percent is achieved [183] and is then maintained at that level through 2029. The savings from energy efficiency programs are cumulative, meaning that, in simplified terms, a state in which a sustained program is implemented with a 1.5 percent annual incremental savings rate could expect cumulative annual savings of approximately 1.5 percent after the first year, 3.0 percent after the second year, 4.5 percent after the third year, and so on. Savings from the first year would drop off at the end of the average life of the energy efficiency program portfolio (typically about ten years). Accordingly, we have projected the cumulative annual savings for each state that would be achieved for the period 2020 to 2029 based on the state's reaching and then sustaining the best practices annual incremental savings rate through 2029. These values, for each state and for each year (2020–2029), are used in the procedure for computing the state goals described in Section VII.C below.

As discussed in Section VII.E below, the EPA is also taking comment on a less stringent alternative for setting state goals. Under this alternative, the demand-side energy efficiency requirement uses 1.0 percent (rather than 1.5 percent) annual incremental savings as representative of the best-practices level of performance. In addition, the pace at which incremental savings levels are increased from their historical levels is relaxed slightly to 0.15 percent per year (rather than 0.2 percent). The 1.0 percent rate of savings is a level of performance that has been achieved—or that established state requirements will cause to be achieved—by 20 states.[184] As is done with the more stringent goal-setting approach for energy efficiency, the cumulative percentages for each state are derived and multiplied by the state's 2012 historical electricity sales as reflected in the EIA detailed state data, in this case for the period from 2020 to 2024.

The state-specific cumulative annual electricity saving data inputs for both the proposed approach and the less stringent alternative are discussed in the Greenhouse Gas Abatement Measures TSD and summarized in Table 7.

TABLE 7—DEMAND-SIDE ENERGY EFFICIENCY STATE GOAL DEVELOPMENT: CUMULATIVE ANNUAL ELECTRICITY SAVINGS (PERCENTAGE OF ANNUAL SALES) RESULTING FROM BEST PRACTICES SCENARIO [185]

State	1.5% Savings target scenario		1.0% Savings target scenario	
	2020	2029	2020	2024
Alabama	1.4	9.5	1.1	3.9
Alaska	1.2	9.5	0.9	3.7
Arizona	5.2	11.4	3.5	6.0
Arkansas	1.5	9.7	1.2	4.1
California	5.0	11.6	3.6	6.1
Colorado	3.9	11.0	3.3	5.9
Connecticut	4.7	11.9	3.6	6.3
Delaware	1.1	9.5	0.9	3.6
Florida	2.0	10.0	1.8	4.7
Georgia	1.8	9.8	1.5	4.4
Hawaii	1.3	9.5	1.0	3.8
Idaho	3.8	11.1	3.5	5.9
Illinois	4.4	11.6	3.5	6.2
Indiana	3.2	11.1	2.9	5.7
Iowa	4.7	11.7	3.6	6.0
Kansas	1.2	9.5	0.9	3.7
Kentucky	1.9	10.0	1.6	4.6
Louisiana	1.1	9.3	0.9	3.6
Maine	5.4	12.1	3.6	6.3
Maryland	4.2	11.5	3.5	6.1
Massachusetts	4.4	11.8	3.6	6.2
Michigan	4.6	11.8	3.6	6.2
Minnesota	4.8	11.7	3.6	6.2
Mississippi	1.4	9.6	1.1	3.9
Missouri	1.6	9.9	1.3	4.2
Montana	3.4	10.9	3.0	5.7
Nebraska	2.2	10.4	1.9	4.9
Nevada	3.0	10.7	2.7	5.5
New Hampshire	2.8	11.0	2.6	5.5
New Jersey	1.3	9.6	1.0	3.7
New Mexico	3.1	10.6	2.8	5.5
New York	4.4	11.8	3.5	6.2
North Carolina	2.4	10.3	2.1	5.0
North Dakota	1.4	9.7	1.1	4.0
Ohio	4.2	11.6	3.5	6.1
Oklahoma	1.9	10.0	1.6	4.5
Oregon	4.7	11.4	3.6	6.1
Pennsylvania	4.7	11.7	3.6	6.2

[183] For example, a state with a reported savings rate of 0.5% in 2012 is assumed to realize a 2017 savings rate of 0.5% and their savings rates for 2018, 2019, 2020, 2021 and 2022 are calculated to be 0.7%, 0.9%, 1.1%, 1.3%, and 1.5%, respectively. By this method, all states have reached the 1.5% target rate by 2017 at the earliest and by 2025 at the latest.

[184] See the Greenhouse Gas Abatement Measures TSD for more information.

TABLE 7—DEMAND-SIDE ENERGY EFFICIENCY STATE GOAL DEVELOPMENT: CUMULATIVE ANNUAL ELECTRICITY SAVINGS (PERCENTAGE OF ANNUAL SALES) RESULTING FROM BEST PRACTICES SCENARIO [185]—Continued

State	1.5% Savings target scenario		1.0% Savings target scenario	
	2020	2029	2020	2024
Rhode Island	3.9	11.6	3.4	6.1
South Carolina	2.3	10.2	2.0	4.9
South Dakota	1.6	9.9	1.3	4.2
Tennessee	2.2	10.3	1.9	4.9
Texas	1.8	9.9	1.5	4.4
Utah	3.6	11.0	3.2	5.8
Virginia	1.2	9.3	1.0	3.7
Washington	4.2	11.3	3.5	6.0
West Virginia	1.8	10.1	1.5	4.4
Wisconsin	4.7	11.8	3.6	6.2
Wyoming	1.6	9.7	1.3	4.2

c. Costs of Demand-Side Energy Efficiency

The EPA expects implementation of demand-side energy efficiency policies as reflected in the best practices scenario to be achievable at reasonable costs. The EPA finds support for the reasonableness of the costs of this building block from two perspectives. First, the specific savings levels represented by this building block were developed based upon the experience and success of states in developing and implementing energy efficiency policies that they undertake primarily for the purpose of providing economic benefits to electricity consumers in their state. Secondly, even with notably conservative assumptions about the costs of achieving the levels of electricity savings associated with this building block, the EPA's analysis of the power sector indicates that the costs are reasonable.

The processes by which states develop funding for energy efficiency programs typically require the application of cost-effectiveness tests to ensure that adopted program portfolios lead to lower costs than the use of generation sources that would otherwise be required to meet the associated electricity service demands. Indeed, a major reason for the widespread presence and rapid growth of demand-side energy efficiency programs is the strong evidence of the reasonableness of their costs even before the additional benefit of CO_2 reductions is considered.[186] Independent studies have found that end-users' needs for energy-dependent services (e.g., heating, cooling, lighting, motor output, and information and entertainment services) frequently can be satisfied at lower cost by improving the efficiency of electricity consumption rather than by increasing the supply of electricity.[187] These factors indicate that the cost of CO_2 reductions achieved through implementation of demand-side energy efficiency at the levels reflected in the best practices scenario are likely to be very reasonable, typically resulting in reductions in average electricity bills across all end-use sectors.[188] Because demand-side energy efficiency costs are incurred at the time of investment, while the cost savings (from lower electricity usage) are realized over the life of these investments (typically about 10 years), bill reductions are greater in later years, but provide substantial payback over the investment period.

Another approach to evaluating the reasonableness of the costs associated with this building block is to compare the demand-side energy efficiency costs to the avoided power system costs as represented within the EPA's modeling of the power sector. The costs associated with the best practices scenario were estimated based upon a synthesis of data and analysis of the factors that impact energy efficiency program costs as calculated using an engineering-based, bottom-up approach that is standard for state and utility analysis of these policies. These factors include the average energy efficiency program costs per unit of first-year energy savings ($/MWh), the ratio of program to participant costs, and the lifetimes of energy efficiency measures across the full portfolio of programs. In addition, the EPA has included a cost escalation factor to represent the possibility of increased costs associated with higher levels of incremental energy savings rates and the national scope of the best practices scenario. The EPA has taken a conservative approach to each of these factors, selecting values that are at the higher-cost end of reasonable ranges of estimated values. The combination of these factors is reflected in the value the EPA has derived for the levelized cost per MWh of saved energy. This value includes both the program costs paid by utilities for implementing energy efficiency programs and the amounts that program participants pay for their own energy efficiency improvements beyond the program costs. These costs are levelized across the measure lifetimes of a full portfolio of energy efficiency programs. This analysis provides a levelized cost of saved energy (LCOSE) range of $85/MWh to $90/MWh ($2011) over the 2020 to 2030 period. This range of LCOSE is notably conservative (leading to higher costs) in comparison with most utility and state analysis. For example, a 2014 analysis by the American Council for an Energy-Efficient Economy (ACEEE) surveyed program and participant cost results across seven states and found a comparable LCOSE value of $54/MWh (2011$).[189]

[185] Vermont and the District of Columbia are excluded from this table because we are not proposing goals for those jurisdictions.

[186] Some states do include a valuation of CO_2 benefits as part of their evaluations of cost effectiveness.

[187] E.g., Electric Power Research Institute, U.S. Energy Efficiency Potential Through 2035 (Final Report, April 2014); Northwest Power and Conservation Council, Sixth Northwest Conservation and Electric Power Plan (Feb. 2010), available at *http://www.nwcouncil.org/energy/powerplan/6/plan/*.

[188] As described below and in the Goal Computation TSD, in the case of a state that is a net importer of electricity, the proposed goal computation procedure includes an adjustment to account for the possibility that some of the generation and emissions avoided due to the state's demand-side energy efficiency programs may occur at EGUs in other states. Given the extremely low cost of CO_2 emission reductions achievable through demand-side energy efficiency programs, implementation of such programs is likely to reduce CO_2 emissions at reasonable cost even for a state whose own affected EGUs achieve only part of the CO_2 emission reduction benefit from the state's demand-side energy efficiency efforts.

[189] American Council for an Energy-Efficient Economy (ACEEE), The Best Value for America's Energy Dollar: A National Review of the Cost of

To estimate the reductions in power system costs and CO_2 emissions associated with the best-practices level of demand-side energy efficiency described above, the EPA analyzed a scenario incorporating the resulting reduction in electricity demand and compared the results with the business-as-usual scenario. Both analyses were conducted using the Integrated Planning Model (IPM) described previously. Combining the resulting power system cost reductions with the energy efficiency cost estimates associated with the best practices scenario, the EPA derived net cost impacts for 2020, 2025, and 2030. Dividing these net cost impacts by the associated CO_2 reductions for each year, the EPA found that the average cost of the CO_2 reductions achieved ranged from $16 to $24 per metric ton of CO_2. The EPA views these estimated costs as reasonable. Together with the history of demonstrated successful state implementation of demand-side energy efficiency programs at reasonable costs discussed above, this analysis supports the reasonableness of the level of demand-side energy efficiency represented by the best practices scenario and, by extension, the reasonableness of the emission reductions at affected EGUs that can be achieved consistent with achievement of that level of demand-side energy efficiency.

Further details regarding the data and methodology used to evaluate the potential for demand-side energy efficiency programs to substitute for generation at affected EGUs and thereby facilitate reductions of power sector CO_2 emissions at reasonable costs are provided in the Greenhouse Gas Abatement Measures TSD. We invite comment on all aspects of our data and methodology as discussed above and in the TSD, as well as on the level of reductions we propose to define as best practices suitable for representation consistent with the best system of emission reduction and the level reflected in the less stringent scenario. We also specifically invite comment on several issues: (1) Increasing the annual incremental savings rate to 2.0 percent and the pace of improvement to 0.25 percent per year to reflect an estimate of the additional electricity savings achievable from state policies not reflected in the 1.5 percent rate and the 0.20 percent per year pace of improvement, such as building energy codes and state appliance standards, (2) alternative approaches and/or data sources (i.e., other than EIA Form 861) for determining each state's current level of annual incremental electricity savings, and (3) alternative approaches and/or data sources for evaluating costs associated with implementation of state demand-side energy efficiency policies.

5. Potential Emission Reduction Measures Not Used To Set Proposed Goals

There are four additional potential measures for reducing, or supporting reduced, GHG emissions from EGUs that the EPA does not propose to consider part of the best system of emission reduction adequately demonstrated for existing EGUs at this time and therefore has not used for goal-setting purposes, but that merit discussion here: Fuel switching at individual EGUs, carbon capture and storage (CCS), using expanded amounts of less carbon-intensive new NGCC capacity to provide replacement generation, and heat rate improvements at affected EGUs other than coal-fired steam EGUs.

a. Fuel Switching at Individual Units

One technically feasible approach for reducing CO_2 emissions per MWh of generation from an EGU designed for coal-fired generation is to substitute natural gas for some or all of the coal. Most existing coal-fired steam EGU boilers can be modified to switch to 100 percent gas input or to co-fire gas with coal in any desired proportion. For certain individual EGUs, switching to or co-firing with gas may be an attractive option for reducing CO_2 emissions.

Changing the type of fuel burned at a steam EGU typically requires certain plant modifications (e.g., new burners) and may have some negative impact on the net efficiencies of the boiler and the overall generation process. If the plant lacks existing gas pipeline infrastructure capable of delivering the necessary quantities of natural gas to the boiler, installation of a new pipeline lateral would also be required.

The capital costs of plant modifications required to switch a coal-fired EGU completely to natural gas are roughly $100–300/kW, excluding pipeline costs. For plants that require additional pipeline capacity, the capital cost of constructing new pipeline laterals is approximately $1 million per mile of pipeline built. Offsetting these capital costs, conversion to 100 percent gas input would typically reduce the EGU's fixed operating and maintenance costs by about 33 percent due mainly to certain equipment retirements and a reduction in staffing, while non-fuel variable costs would be reduced by about 25 percent due to reduced maintenance and waste disposal costs. However, in most cases, the most significant cost change associated with switching from coal to gas in a coal-fired boiler is likely to be the difference in fuel cost. Using EIA's projections of future coal and natural gas prices, switching a steam EGU's fuel from coal to gas typically would more than double the EGU's fuel cost per MWh of generation.

The CO_2 reduction potential of natural gas co-firing or conversion is due largely to the different carbon intensities of coal and natural gas and is directly related to the proportion of gas burned. Greater reductions in the CO_2 emission rate are achieved at higher proportions of gas usage. For example, at ten percent gas co-firing, the net emission rate (e.g., pounds of CO_2 per net MWh of generation) of a typical steam EGU previously burning only coal would decrease by approximately four percent. At 100 percent gas burn, the net emission rate of a typical steam EGU previously burning only coal would decrease by approximately 40 percent.

For a typical base-load coal-fired EGU, and reflecting EIA's projected future natural gas and coal prices, the average cost of CO_2 reductions achieved through gas conversion or co-firing ranges from $83 per metric ton to $150 per metric ton. The low end of the range of CO_2 reduction costs represents a 100 percent switch to gas, because in instances where a combination of coal and gas is burned, the EGU would continue to bear the fixed costs associated with equipment needed for coal combustion, raising the cost per ton of CO_2 reduced.

The EPA's economic analysis suggests that there are more cost effective opportunities for coal-fired utility boilers to reduce their CO_2 emissions than through natural gas conversion or co-firing. As a result, the EPA has not proposed at this time to include this option in the BSER and has not incorporated implementation of the option into the proposed state goals. However, the EPA believes that there are a number of factors that warrant further consideration in determining whether the option should be included. First, the EPA is aware that a number of utilities have reworked some of their coal-fired units to allow for some level of natural gas co-firing (and in some cases have converted the units to fire entirely on natural gas). Second, the EPA is aware of several possible reasons beyond reduction of CO_2 emissions that may make natural gas co-firing economically attractive in some circumstances. One example is that natural gas reburn strategies that involve

Utility Energy Efficiency Programs (Report No. U1402, March 2014).

co-firing with 10 to 20 percent natural gas can be an effective control strategy for NO_X emissions and, thus, can offset operational (and in some cases, capital) costs associated with other NO_X controls such as selective catalytic reduction (SCR) or selective non-catalytic reduction (SNCR). A second example suggested by some vendors is that the capability to burn natural gas in a coal-fired boiler can improve economics because it allows the boiler to operate more effectively at lower loads. A third example, applicable to units that run infrequently but may be needed for reliability purposes, is that converting to or co-firing with natural gas may be more economically attractive than either installing non-CO_2 emission controls or taking other measures, such as transmission upgrades, that could become necessary if the unit were retired. Finally, beyond the reasons just described explaining why EGU owners may find natural gas co-firing to be cost-effective, there are also potentially significant health co-benefits associated with burning natural gas instead of coal.

We solicit comment on whether natural gas co-firing or conversion should be part of the BSER. We also request comment regarding whether, and, if so, how, we should consider the co-benefits of natural gas co-firing in making that determination.

b. Carbon Capture and Storage

Another possible approach for reducing CO_2 emissions from existing fossil fuel-fired EGUs is through the application of carbon capture and storage [190] technology (CCS). In the recently proposed standards of performance for new fossil fuel-fired EGUs (79 FR 1430), the EPA proposed to find that the best system of emission reduction for new fossil fuel-fired boilers and IGCC units is partial application of CCS. In that proposal, the EPA found that, for new units, partial CCS has been adequately demonstrated, it is technically feasible, it can be implemented at costs that are not unreasonable, it provides meaningful emission reductions, and its implementation will serve to promote further development and deployment of the technology. The EPA also noted in the proposal that most of the relatively few new boiler and IGCC EGU projects currently under development are already planning to implement CCS, and, as a result, the proposed standard would not have a significant impact on nationwide energy prices.

In contrast, the EPA did not identify full or partial CCS as the BSER for new natural gas-fired stationary combustion turbines, noting technical challenges to implementation of CCS at NGCC units as compared to implementation at new solid fossil fuel-fired sources. The EPA also noted that, because virtually all new fossil fuel-fired power projects are projected to use NGCC technology, requiring full or partial CCS would have a greater impact on the price of electricity than requiring CCS at the few projected coal plants, and the larger number of NGCC projects would make a CCS requirement difficult to implement in the short term.

Partial CCS has been demonstrated at existing EGUs. It has been demonstrated at a pilot-scale at Southern Company's Plant Barry, it is being installed for large-scale demonstration at NRG's W.A. Parish facility, and it is expected soon to be applied at a commercial scale as a retrofit at SaskPower's Boundary Dam plant in Canada. However, the EPA expects that the costs of integrating a retrofit CCS system into an existing facility would be substantial. For example, some existing sources have a limited footprint and may not have the land available to add a CCS system. Moreover, there are a large number of existing fossil-fired EGUs. Accordingly, the overall costs of requiring CCS would be substantial and would affect the nationwide cost and supply of electricity on a national basis.

For the reasons just described, based on the information available at this time, the EPA does not propose to find that CCS is a component of the best system of emission reduction for CO_2 emissions from existing fossil fuel-fired EGUs. The EPA does solicit comment on all aspects of applying CCS to existing fossil fuel-fired EGUs (in either full or partial configurations), but does not expect to finalize CCS as a component of the BSER in this rulemaking. It should be noted, however, that in light of the fact that several existing fossil-fired EGUs are currently being retrofitted with CCS, the implementation of partial CCS may be a viable GHG mitigation option at some facilities, and as a result, emission reductions achieved through use of the technology could be used to help meet the emission performance level required under a state plan.

Additional discussion can be found in the Greenhouse Gas Abatement Measures TSD.

c. New NGCC Capacity

In Section VI.C.2 above, we discussed the opportunity to reduce CO_2 emissions by replacing generation at high carbon-intensity affected EGUs with lower-carbon generation from existing NGCC units.[191] From a technical perspective, the same potential would exist to replace high-emitting generation with generation from additional NGCC capacity that may be built in the future; the analysis above regarding the feasibility of policies to increase utilization rates of existing NGCC units on average to 70 percent applies equally to new NGCC units.[192] We view the opportunity to reduce CO_2 emissions at affected EGUs by means of addition and operation of new NGCC capacity as clearly feasible.

In addition, we note that our compliance modeling for this proposal suggests that the construction and operation of new NGCC capacity will be undertaken as method of responding to the proposal's requirements.

However, compared to the opportunity to reduce CO_2 emissions at affected EGUs by means of re-dispatch to existing NGCC capacity, the parallel opportunity involving new NGCC capacity would be more costly for several reasons. The first reason is the additional cost associated with additional usage of natural gas. As noted in the discussion of building block 2 above, the EPA analyzed costs associated with several different target utilization rates for existing NGCC units and that analysis showed higher costs of CO_2 reductions at higher target NGCC utilization rates.

The second reason that emission reductions from the use of new NGCC capacity would be more costly is that there would be capital investment costs. Some amount of new NGCC capacity (beyond the units that were already under construction as of January 8, 2014 and are ''existing'' units for purposes of this proposal) would likely be built to meet perceived electricity market demand or to replace less economic capacity regardless of this proposal. The costs of achieving CO_2 emission reductions through re-dispatch to these new NGCC units and through re-dispatch to existing NGCC units would be comparable (ignoring consideration

[190] This is also sometimes referred to as ''carbon capture and sequestration.''

[191] For purposes of this proposal, NGCC units that have commenced construction as of January 8, 2014 are ''existing'' units.

[192] Whether and to what extent adding new NGCC capacity is likely to lead to CO_2 reductions depends on what incentives would exist to operate that new capacity in preference to operation of more carbon-intensive existing EGUs. Because the proposed state goals also reflect the opportunity to reduce utilization of high carbon-intensity EGUs by shifting generation to less carbon-intensive EGUs, we believe that in the context of a comprehensive state plan, the necessary incentives would likely exist, in which case adding new NGCC capacity would tend to reduce CO_2 emissions.

of the cost impacts just discussed related to increases in overall gas usage). However, in the case of any new NGCC units that would not have been built if not for this proposal, and that were built in part for the purpose of achieving CO_2 reductions at affected EGUs, some portion of their construction or fixed operating costs would also be attributable to the CO_2 reduction opportunity, increasing to some extent the cost of the CO_2 reductions at affected EGUs achieved through re-dispatch to those new NGCC units.

The third reason relates to the costs of pipeline infrastructure expansion, and in particular the unevenly distributed nature of those costs. While expanded use of existing NGCC capacity to achieve CO_2 emission reductions can be expected to rely largely on existing pipeline infrastructure with incremental capacity expansions, use of new NGCC capacity—if required in all states—could require substantially greater pipeline infrastructure investments to serve some states than others.

Taken together, the EPA believes the cost considerations just described indicate a higher cost for CO_2 reductions achievable from re-dispatch to new NGCC capacity than from other options, at least for states with limited natural gas pipeline infrastructure, and we therefore do not propose to include this option in state goals.

While the EPA is not proposing that new NGCC capacity is part of the basis supporting the BSER, we recognize that there are a number of new NGCC units being proposed and that many modeling efforts suggest that development of new NGCC capacity would likely be used as a CO_2 emission mitigation strategy. Therefore, we invite comment on whether we should consider construction and use of new NGCC capacity as part of the basis supporting the BSER. Further, we take comment on ways to define appropriate state-level goals based on consideration of new NGCC capacity.

d. Assessment of Heat Rate Improvement Opportunities at Oil-Fired Steam EGUs, Gas-Fired Steam EGUs, NGCC Units, and Simple-Cycle Combustion Turbine Units

The EPA assessed opportunities to improve heat rates at affected EGUs other than coal-fired steam units. This assessment, which is documented in a Technical Memorandum included as an appendix to the GHG Abatement Measures TSD, considers the potential extent of heat rate improvements and CO_2 reductions that could be reasonably available from oil-fired steam EGUs, gas-fired steam EGUs, NGCC units, and simple-cycle combustion turbine units. For these non-coal technologies, the total additional potential CO_2 reductions achievable through heat rate improvements appear relatively small compared to the potential CO_2 reductions achievable through heat rate improvements at coal-fired steam EGUs. For this reason, the EPA does not propose to include heat rate improvement opportunities at these other fossil fuel-fired units as an element of the BSER for CO_2 emissions from affected EGUs at this time. However, we are aware that the proportion of total generation provided from EGUs such as oil-fired steam EGUs or gas-fired steam EGUs varies by location, and may be relatively large in geographically isolated areas such as islands. We therefore invite comment on whether heat rate improvements for some of the EGU types discussed above should be identified as a basis for supporting the BSER, with particular reference to U.S. territories.

Finally, the EPA expects that for some individual oil/gas-fired steam EGUs and NGCC units attractive heat rate improvement opportunities will exist. We note that under the proposed flexible approach to state plans described later in this preamble, CO_2 reductions achieved through such opportunities could be used to help meet state goals, regardless of whether these measures are used as a basis to support the BSER.

D. Potential Combinations of the Building Blocks as Components of the Best System of Emission Reduction

This subsection summarizes the EPA's examination of combinations of the building blocks as components of the BSER, comparing the merits of a potential BSER that comprises only building blocks 1 and 2 with the merits of a BSER that comprises all four building blocks—the preferred option in this proposal. (A more detailed discussion of how we evaluated each option against the criteria to be considered for the BSER follows in Section VI.E.) [193]

1. Reasons for Considering Combinations of Building Blocks

As previously described, the building blocks can be summarized as follows:

Building block 1: Reducing the carbon intensity of generation at individual affected EGUs through heat rate improvements.

Building block 2: Reducing emissions from the most carbon-intensive affected EGUs in the amount that results from substituting generation at those EGUs with generation from less carbon-intensive affected EGUs (including NGCC units under construction).

Building block 3: Reducing emissions from affected EGUs in the amount that results from substituting generation at those EGUs with expanded low- or zero-carbon generation.

Building block 4: Reducing emissions from affected EGUs in the amount that results from the use of demand-side energy efficiency that reduces the amount of generation required.

The EPA initially considered a BSER comprising only strategies within building block 1. As described earlier in Section VI.B, the EPA concluded that certain strategies within building block 1—specifically heat rate improvements at individual coal-fired steam EGUs—should be a component of the BSER determination, as they are technically feasible and can be implemented at a reasonable cost. However, the EPA further concluded that, while heat rate improvements qualify as a system of emission reduction, they are not in themselves the BSER as there are additional strategies that can be utilized in combination with building block 1 that are technically feasible, can be implemented at reasonable cost, and result in greater emission reductions than would be achieved through building block 1 strategies alone. The EPA is also concerned that if the measures that improve heat rates at coal-fired steam EGUs in building block 1 are implemented in isolation, without additional measures that reduce overall electricity demand or encourage substitution of less carbon-intensive generation for more carbon-intensive generation, the resulting increased efficiency of coal-fired steam units would provide incentives to operate those EGUs more, leading to smaller overall reductions in CO_2 emissions. Further, in listening sessions and other outreach meetings, the EPA learned that states and other sources were already implementing and pursuing strategies in the other building blocks for the purpose, at least in part, of reducing CO_2 emissions.

2. A Combination of Building Blocks 1 and 2 as the Best System of Emission Reduction

We considered a BSER that comprises strategies from building blocks 1 and 2.

[193] For convenience, the discussion in this Section VI.D is based on our proposal to identify the BSER as consisting of the building blocks themselves. The points made in this discussion are also relevant for our alternative proposal to identify the BSER as consisting of building block 1 coupled with reduced utilization of the affected EGUs in specified amounts.

In this system, emission reductions at the most carbon-intensive individual affected EGUs would occur through a combination of heat rate improvements (resulting in a decrease in emission rates) and substitution of generation at less carbon-intensive affected EGUs, notably existing NGCC units. One reason for considering a BSER comprising these two building blocks is that it involves only affected EGUs and generation from affected EGUs.

The EPA believes that the combination of building blocks 1 and 2 would be a ''system of emission reduction'' capable of achieving significant reductions in CO_2 emissions from affected EGUs at a reasonable cost. As discussed in Section VI.C above, each of the two building blocks independently would be capable of achieving meaningful CO_2 emission reductions at reasonable costs. In combination, the need to achieve the level of emission reductions achievable through use of building block 2 can mitigate the concern that building block 1, implemented alone, would make coal-fired EGUs more economically competitive and lead to increased generation that would offset the emission reduction benefits of the carbon-intensity improvements. While combining the building blocks may also raise the cost per ton of emission reductions achieved through heat rate improvements (by reducing the quantity of MWh generated from the EGUs with improved heat rates and therefore also reducing the aggregate emission reductions achieved at those EGUs by the heat rate improvements), the costs of heat rate improvements are low enough that we believe their cost per ton of emission reduction would remain reasonable.

Nevertheless, the EPA is not proposing that a combination of building blocks 1 and 2 is the BSER, because the proposed combination of all four building blocks discussed below—in other words, adding to the measures in building blocks 1 and 2 the measures in building blocks 3 and 4, which we and stakeholders have identified as already in use—is capable of achieving even greater CO_2 emission reductions from affected EGUs at reasonable costs. The state-specific goals that would be computed consistent with a BSER based on the combination of only building blocks 1 and 2 (i.e., goals computed using the goal computation methodology discussed in Section VII below, except for the omission of building blocks 3 and 4) are presented in the Goal Computation TSD available in the docket. Further information on the EPA's evaluation of this combination is available in the ''Analysis of Emission Reductions, Costs, Benefits and Economic Impacts Associated with Building Blocks 1 and 2'' available in the docket. We invite comment on a potential BSER comprising a combination of building blocks 1 and 2.

3. A Combination of all Four Building Blocks as the Best System of Emission Reduction

Our proposal for the BSER is a combination of all four building blocks. As discussed in Section VI.C above, each of the four building blocks is a proven way to support either improvements in emissions rates at affected EGUs or reductions in EGU mass emissions; each is in widespread use and is independently capable of supporting significant CO_2 reductions from affected EGUs, either on an emission rate or mass-emissions basis, at a reasonable cost consistent with ensuring system reliability. As discussed in Section VI.E below, the combination of all four building blocks provides the basis for satisfying the legal criteria to be considered the BSER. Further, as discussed in Section X below, the combination of all four building blocks can achieve greater overall CO_2 emission reductions from affected EGUs, at a lower cost per unit of CO_2 eliminated, than the combination of building blocks 1 and 2.

In the large and highly integrated electricity system, where electricity is fungible and the demand for electricity services can be met in many ways (including through demand-side energy efficiency), states and the industry have long pursued a wide variety of strategies for ensuring that the demand for electricity services is met reliably, at reasonable costs, and in a manner consistent with evolving constraints, including environmental objectives. These strategies have long extended to the measures in all four building blocks. We believe the combination of all four building blocks fairly represents the range of measures that states and the industry will consider when developing state plans and strategies for reducing CO_2 emissions from affected EGUs while continuing to meet demand for electricity services reliably and affordably. Therefore, we believe it is appropriate to consider that same combination as the BSER upon which the required CO_2 standards of performance for affected EGUs should be based.

E. Determination of the Best System of Emission Reduction

1. Overview

In this section, the EPA explains the ''best system of emission reduction . . . adequately demonstrated.'' This explanation includes what the EPA proposes to determine as the BSER and why. In addition the EPA explains how the BSER forms the basis for each state's overall emission limitation requirement, which the EPA determines as the state goal and the state adopts into its planning process as the emissions performance level. The emission performance level, in turn, constitutes the minimum degree of stringency for the standards of performance that, taken as a whole, the state must establish for its affected EGUs (or, if the state adopts the portfolio approach, for the requirements imposed on the affected EGUs and other entities). Through this process, the BSER informs the minimum stringency of the standards of performance, although the state retains flexibility in its allocation of emission limitations among its sources. As the EPA explains, central to this overall approach is the fact that the EPA applies the BSER on a state-wide basis, which is consistent with the interconnected nature of the electricity system.

The EPA is proposing two alternative formulations for the BSER, each of which is based on, although in different ways, the four building blocks. Under the first approach, emission rate improvements and mass emission reductions at affected EGUs facilitated through the adoption of the four building blocks themselves meet the criteria for the BSER because they will amount to substantial reductions in CO_2 emissions achieved while maintaining fuel diversity and a reliable, affordable electricity supply for the United States. Under the second approach, the BSER consists of building block 1 coupled with reduced utilization in specified amounts from, in general, higher-emitting affected EGUs. Under this latter approach, the measures in building blocks 2, 3, and 4 serve to justify those amounts and the ''adequate[ ] demonstrat[ion]'' because they are proven measures that are already being pursued by states and the industry, at least in part for the purpose of reducing CO_2 emissions from affected EGUs.

The remainder of this discussion is organized into the following subsections. Subsection 2 contains a summary of relevant considerations for the BSER as defined in the statute and further interpreted in court decisions. Subsection 3 discusses characteristics of the electricity industry relevant to interpretation of the BSER for purposes of this proposal, most notably the industry's highly interconnected and integrated nature. Subsection 4 provides a discussion of how the building blocks would satisfy the BSER criteria in isolation or support the alternative formulation of the BSER as including reduced utilization in specified amounts. Subsection 5 evaluates two combinations of building blocks—a combination of building blocks 1 and 2, and the proposed combination of all four building blocks—against the BSER criteria, and explains why we propose that the combination of all four is the BSER. Subsection 6 addresses additional considerations related to the inclusion of building blocks 2, 3, and 4 as parts of the basis supporting the BSER. In subsection 7, we describe and seek comment on the alternate interpretation that the BSER includes, in addition to building block 1, a component consisting of reduced generation from higher-emitting affected EGUs, with the measures in the other building blocks serving as the basis for quantifying the amounts of generation reductions and consequent CO_2 emission reductions that can be achieved while continuing to meet the demand for electricity services in a reliable and affordable manner. In subsection 8, we discuss the discretion that the case law gives us in weighing the various criteria to determine the BSER. In subsection 9, we discuss how the BSER and the state-wide manner in which the EPA applies it form the basis for the emission standards that the state includes in the plan, and we explain why that approach is consistent with the applicable section 111 requirements. The final three subsections address the topics of combining source categories, severability, and certain other specific issues on which we are seeking comment. Additional discussion is provided in the Legal Memorandum available in the docket.

2. Statutory and Regulatory Provisions Related to Determination and Application of the BSER

The EPA's explanation for this BSER proposal begins with the statutory definition of a ''standard of performance'':

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

42 U.S.C. 7411(a)(1).

The U.S. Court of Appeals for the D.C. Circuit (D.C. Circuit or Court) has handed down case law over a 40-year period that interprets this CAA provision, including its component elements.[194] Under this case law, the EPA determines the BSER based on the following key considerations, among others:

- The system of emission reduction must be technically feasible.
- The EPA must consider the amount of emission reductions that the system would generate.
- The costs of the system must be reasonable. The EPA may consider costs at the source level, the industry level, and, at least in the case of the power sector, the national level in terms of the overall costs of electricity and the impact on the national economy over time.[195]
- The EPA must also consider that CAA section 111 is designed to promote the development and implementation of technology, including the diffusion of existing technology as the BSER,[196] the development of new technology that may be treated as the BSER,[197] and the development of other emerging technology.[198]

Another consideration particularly relevant to this rulemaking is energy impacts, which, as with costs, the EPA may consider at the source level, the industry level, and the national level over time. In the context of the electricity industry and this proposal, the EPA believes that the scope of energy impacts that may be considered encompasses assurance of the continued ability of the industry to meet the evolving demand for electricity services in a reliable manner, while providing sufficient flexibility to enable affected sources to follow state energy plans.

Importantly, the EPA has discretion to weigh these various considerations, may determine that some merit greater weight than others, and may vary the weighting depending on the source category.

It is a well-established principle that states have discretion regarding the measures adopted in their state implementation plans under CAA section 110 to attain the NAAQS.[199] The EPA believes that the same principle applies in the context of state plans under section 111(d) as well, such that each state has the discretion to adopt emission reduction measures other than the measures found by the EPA to comprise the BSER, or to place greater or lesser emphasis than the EPA on certain measures, provided that the state's plan achieves the required level of emission performance for affected sources.

The EPA discussed the CAA requirements and Court interpretations of the BSER at length in the January 2014 Proposal, 79 FR at 1,462/1–1,467/3, and incorporates by reference that discussion into this rulemaking.

Over the last forty years, under CAA section 111(d), the agency has regulated four pollutants from five source categories (i.e., phosphate fertilizer plants (fluorides), sulfuric acid plants (acid mist), primary aluminum plants (fluorides), Kraft pulp plants (total reduced sulfur), and municipal solid waste landfills (landfill gases)).[200] In addition, the agency has regulated additional pollutants under CAA

[194] *Portland Cement Ass'n* v. *Ruckelshaus,* 486 F.2d 375 (D.C. Cir. 1973), cert. denied, 416 U.S. 969 (1974); *Essex Chemical Corp.* v. *Ruckelshaus,* 486 F.2d 427 (D.C. Cir. 1973), cert. denied, *Appalachian Power Co.* v. *EPA,* 416 U.S. 969 (1974); *Sierra Club* v. *Costle,* 657 F.2d 298 (D.C. Cir. 1981); *Portland Cement Ass'n* v. *EPA,* 665 F.3d 177 (D.C. Cir. 2011). Although this case law concerns the meaning of the definition of ''standard of performance'' for purposes of rulemakings that the EPA promulgated under CAA section 111(b), the same term is used for section 111(d), and as a result, this case law is relevant for the present rulemaking under section 111(d).

[195] As discussed in the January 2014 Proposal, the D.C. Circuit's case law formulates the cost consideration in various ways: The costs must not be ''exorbitant[ ]'', *Essex Chemical Corp.* v. *Ruckelshaus,* 486 F.2d at 433, see *Lignite Energy Council* v. *EPA,* 198 F.3d 930, 933 (D.C. Cir. 1999); ''greater than the industry could bear and survive,'' *Portland Cement Ass'n* v. *EPA,* 513 F.2d 506, 508 (D.C. Cir. 1975); or ''excessive'' or ''unreasonable,'' *Sierra Club* v. *Costle,* 657 F.2d at 343. In the January 2014 Proposal, the EPA stated that ''these various formulations of the cost standard . . . are synonymous,'' and, for convenience, we used ''reasonableness'' as the formulation. We take the same approach in this rulemaking.

[196] *See* 1970 Senate Committee Report No. 91–1196 at 15 (''The maximum use of available means of preventing and controlling air pollution is essential to the elimination of new pollution problems'').

[197] *See Portland Cement Ass'n* v. *Ruckelshaus,* 486 F.2d at 391 (the best system of emission reduction must ''look[ ] toward what may fairly be projected for the regulated future, rather than the state of the art at present'').

[198] *See Sierra Club* v. *Costle,* 657 F.2d at 351 (upholding a standard of performance designed to promote the use of an emerging technology).

[199] *See Train* v. *Natural Res. Def. Council,* 421 U.S. 60 (1975).

[200] *See* ''Phosphate Fertilizer Plants; Final Guideline Document Availability,'' 42 FR 12022 (Mar. 1, 1977); ''Standards of Performance for New Stationary Sources; Emission Guideline for Sulfuric Acid Mist,'' 42 FR 55796 (Oct. 18, 1977); ''Kraft Pulp Mills, Notice of Availability of Final Guideline Document,'' 44 FR 29828 (May 22, 1979); ''Primary Aluminum Plants; Availability of Final Guideline Document,'' 45 FR 26294 (Apr. 17, 1980); ''Standards of Performance for New Stationary Sources and Guidelines for Control of Existing Sources: Municipal Solid Waste Landfills, Final Rule,'' 61 FR 9905 (Mar. 12, 1996).

section 111(d) in conjunction with CAA section 129.[201] However, the agency has not previously regulated CO_2 or any other greenhouse gas under CAA section 111(d) (although because landfill gases include methane, the agency's regulation of landfill gases reduced emissions of that greenhouse gas). Further, the electricity industry differs in important ways from the source categories previously regulated under section 111(d) in terms of its large scale, its central importance to the economy, and, as discussed below, its highly interconnected and integrated nature.

3. The Interconnected Nature of the U.S. Electricity Sector

The U.S. electricity system is a highly interconnected, integrated system in which large numbers of EGUs using diverse fuels and generating technologies are operated in a coordinated manner to produce fungible electricity services for customers. Because electricity storage is costly and has not been widely deployed, the amounts of electricity demanded and supplied must be continuously matched, and system operators typically have flexibility to choose among multiple EGUs when selecting where to obtain the next MWh of generation needed. Coordination over short- and long-term time scales is accomplished through a variety of institutions including vertically integrated utilities, state regulatory agencies, independent system operators and regional transmission organizations (ISOs/RTOs), and market mechanisms. The electricity sector is both critical to the nation's economy and the source of more than 30 percent of U.S. greenhouse gas emissions, predominantly in the form of CO_2.

The integrated electricity system allows increased generation from less carbon-intensive NGCC units to substitute for generation from more carbon-intensive steam EGUs (building block 2), thereby lowering CO_2 emissions from the group of affected EGUs as a whole. The electricity system similarly allows increased generation resulting from expansion of the amount of available low- or zero-carbon generating capacity connected to the electric grid (building block 3), as well as avoided generation resulting from reductions in electricity demand (building block 4), to substitute for fossil fuel-fired generation, thereby reducing CO_2 emissions from affected EGUs. Each of these measures already routinely occurs within this integrated system for providing electricity and electricity services.

The integrated nature of the electricity system has long played a central role in the industry's continuing efforts to assure reliability and to manage costs generally. Specifically in the area of pollution control, state governments and the federal government have repeatedly taken advantage of the integrated nature of the electricity system when designing programs to allow the industry to meet the pollution control objectives in a least-cost manner. Examples include several cap-and-trade programs to reduce national or regional emissions of SO_2 and NO_X: The SO_2-related portion of the CAA Title IV Acid Rain Program, the Ozone Transport Commission (OTC) NO_X Budget Program, the NO_X SIP Call NO_X Budget Trading Program, and the Clean Air Interstate Rule (CAIR) annual SO_2, annual NO_X, and ozone-season NO_X trading programs. While the Acid Rain Program was created by federal legislation, the OTC NO_X Budget Program was developed primarily through the joint efforts of a group of northeastern states. In the NO_X SIP Call and CAIR programs, the federal government set emission budgets and developed trading programs that states could use as a compliance option.[202] Each of these programs was designed to take advantage of the fact that in an integrated electricity system, some EGUs can reduce emissions at lower costs than others, and that by allowing the industry to determine through market mechanisms which EGUs to control and which to leave uncontrolled, and which EGUs to potentially operate more and which to potentially operate less, overall compliance costs can be reduced. The integrated electricity system plays the important function of allowing some EGUs to reduce their generation while ensuring that overall demand for electricity services can be reliably met. It is worth noting that adoption by affected EGUs of any of the measures in the building blocks could be (or could have been) used to facilitate compliance with each of the programs just described.[203]

Some states are already relying on the integrated nature of the electricity system to establish the policy contexts within which affected EGUs will reduce their CO_2 emissions.[204] California and Colorado provide two examples of how statewide targets (or company-wide targets within a state) can be designed with consideration of the wide range of CO_2 mitigation options and affected EGUs' flexibility to use those options.

California enacted its Global Warming Solutions Act (also known as AB32) in 2006, requiring the state to reduce its GHG emissions to 1990 levels by 2020 and 80 percent below 1990 levels by 2050.[205] According to California, ''the integrated nature of the power grid means that policies which displace the need for fossil generation can often cut emissions from covered sources more deeply, and more cost-effectively than can engineering changes at the plants alone, though these source-level control efforts are a vital starting point.'' [206] California therefore relied on a suite of mechanisms to provide fossil fuel-fired generation substitutes and incentives for EGUs to reduce their emissions, including demand-side energy efficiency programs, renewable energy programs, and an economy-wide cap-and-trade program, along with other programs.[207] The California plan has put in place mechanisms that through market dynamics affect both companies' longer-term planning decisions and their short-term dispatch decisions. The need to hold emissions allowances and the reduced demand from demand-side energy efficiency programs impact longer-term decisions companies make about investment in both existing and new EGUs. The price of emission allowances also impacts hourly dispatch decisions; where emission allowance requirements are in effect, EGU owners

[201] *See, e.g.,* ''Standards of Performance for New Stationary Sources and Emission Guidelines for Existing Sources: Sewage Sludge Incineration Units, Final Rule,'' 76 FR 15372 (Mar. 21, 2011).

[202] In the Regional Greenhouse Gas Initiative, described in more detail below, participating states use emission budgets and a trading program to address CO_2 emissions from the electricity sector.

[203] In addition to the already-implemented programs mentioned above—the SO_2-related portion of the Acid Rain Program, the OTC NO_X Budget Program, the NO_X SIP Call NO_X Budget Trading Program, and the Clean Air Interstate Rule trading programs—use of measures in the building blocks would also facilitate compliance with the cap-and-trade programs established by the Cross-State Air Pollution Rule (76 FR 48208, Aug. 8, 2011).

[204] A number of utilities also have climate mitigation plans. Examples include National Grid, *http://www2.nationalgrid.com/responsibility/how-were-doing/grid-data-centre/climate-change/*; Exelon, *http://www.exeloncorp.com/newsroom/pr_20140423_EXC_Exelon2020.aspx*; PG&E, *http://www.pge.com/about/environment/pge/climate/*; and Austin Energy, *http://austinenergy.com/wps/portal/ae/about/environment/austin-climate-protection-plan/!ut/p/a0/04_Sj9CPykssy0xPLMnMz0vMAfGjzOlNjCyMPJwNjDzdzY0sDBzdnZ28TcP8DAMMDPQLsh0VAU4fG7s!/*.

[205] State of California Global Warming Solutions Act of 2006, Assembly Bill 32, *http://www.leginfo.ca.gov/pub/05-06/bill/asm/ab_0001-0050/ab_32_bill_20060927_chaptered.pdf*.

[206] December 27, 2013 Letter from Mary D. Nichols, Chairman of California Air Resources Board, to EPA Administrator Gina McCarthy.

[207] See Cal. Air Res. Bd., Climate Change Scoping Plan 31–32, 41–46 (2008), available at *http://www.arb.ca.gov/cc/scopingplan/document/adopted_scoping_plan.pdf*.

routinely recognize the costs of emission allowances as components of the variable operating costs that are relied on for these decisions.[208] In this manner, allowance prices constitute market signals encouraging reduced use of higher-emitting EGUs and increased use of lower-emitting EGUs.

The Colorado Clean Air, Clean Jobs Act (CACJA), signed into law on April 19, 2010, required each investor-owned utility with coal-fired EGUs to submit to the state a multi-pollutant plan for meeting current and foreseeable EPA standards for emissions of NO_X, SO_2, particulates, mercury, and CO_2. Rather than fully prescribing specific control technologies, the law provided flexibility for each utility to select the best set of measures to achieve the emission reductions.[209] For example, a utility could choose to retrofit or repower EGUs, or it could choose to retire higher-emitting EGUs and replace them with NGCC units and other low- or non-emitting energy plants or with end-use efficiency measures.[210] The Colorado plan generally focused more on impacting companies' longer-term planning decisions than on affecting short-term dispatch decisions. In response, Colorado utilities have adopted a mix of measures including retrofits, natural gas conversions and retirements of coal-fired EGUs, as well as construction of new NGCC units.

Multi-state mechanisms with analogous impacts on both longer-term planning decisions and short-term dispatch decisions have also been put in place. For example, nine northeastern and Mid-Atlantic States [211] participate in the Regional Greenhouse Gas Initiative (RGGI), a market-based emissions budget trading program that sets an aggregate limit on CO_2 emissions from fossil fuel-fired EGUs in the participating states. To comply with the program, each EGU must acquire allowances equal to its emissions in each compliance period—through purchases or by allocation from the state—and must surrender the allowances at the end of the period. The RGGI program offers flexibility to regulated parties through provisions for multi-year compliance periods, allowance banking, offsets, an auction reserve price, and a cost-containment reserve of allowances, and further encourages emission allowance market development by authorizing trading between regulated and non-regulated parties.[212] Operating in this regime, EGUs could take a variety of compliance actions, including replacing generation at higher-emitting EGUs with generation at lower-emitting EGUs or achieving emissions reductions at EGUs by means of end-use energy efficiency programs.

An approach to determination of the BSER that recognizes the integrated nature of the electricity system is also consistent with the way in which the electricity industry already addresses resource planning issues. For example, in states where the price of EGUs' generation remains subject to regulation, utilities generally prepare integrated resource plans setting forth their strategies for meeting future demand for electricity services in a cost-effective manner. These plans may include measures from building blocks 2, 3, and 4. In most states where generation is no longer subject to price regulation, regional transmission organizations (RTOs) or independent system operators (ISOs) ensure the adequacy of future generation supplies by administering auctions for forward capacity. In these auctions, owners of existing EGUs (with consideration of building blocks 1 and 2),[213] developers of new EGUs including renewable generating capacity (building block 3), and developers of demand-side resources (building block 4) all compete to provide potential resources for meeting the projected demand for electricity services.

As indicated by the foregoing discussion, in the U.S. electricity system the demand for electricity services is met, on both a short-term and longer-term basis and in both regulated and deregulated contexts, through integrated consideration of a wide variety of possible options, coordinated by some combination of utilities, regulators, system operators, and market mechanisms. The EPA believes that the BSER for CO_2 emissions from existing EGUs should reflect this integrated character.

A final, important point regarding the integrated electricity system is that the sets of actions that enable the demand for electricity services to be continuously met can be undertaken in different orders, with changes in some interconnected elements eliciting compensating responses from other interconnected elements. Thus, the CO_2 emissions reductions associated with building blocks 2, 3, and 4 can be achieved in either of two ways: (i) First instituting measures in building blocks 2, 3, and 4, which, due to the interconnected and integrated nature of the grid, would elicit the response of reducing generation at some or all affected EGUs, thereby lowering those EGUs' emissions; or (ii) first reducing generation and therefore emissions from some or all affected EGUs (or planning to make those reductions), which due to the interconnected and integrated nature of the grid, would elicit the responses identified in building blocks 2, 3, and 4 of increasing generation at lower-emitting EGUs or reducing the demand for electricity services. (In some cases, the change and response could be planned simultaneously.) Each of these sets of actions, with the building blocks as the initial change or the reduced generation at affected EGUs as the initial change, may be considered to be part of a ''system of emission reduction,'' as discussed below.

Further discussion of the ways in which the ''system of emission reduction'' for affected EGUs is influenced by the interconnected and integrated nature of the electricity system is provided below in the context of the EPA's rationale for proposing to base the BSER on the combination of all four building blocks. This topic is also discussed in the Legal Memorandum available in the docket.

4. Evaluation of Individual Building Blocks Against the BSER Criteria

In this subsection we explain why (i) the individual building blocks meet the criteria to qualify as components of the ''best system of emission reduction . . . adequately demonstrated'' and (ii) why, under the alternative formulation of the BSER as including reduced utilization of higher-emitting affected EGUs in specified amounts, building blocks 2, 3, and 4 serve as the basis for those amounts and why the reduced utilization is ''adequately demonstrated.''

a. Building Block 1—Heat Rate Improvements

Building block 1—reducing the carbon intensity of generation at individual affected coal-fired steam EGUs through heat rate improvements—is a component of the BSER because the measures the affected sources may

[208] The requirement to hold allowances covering their CO_2 emissions went into effect for EGUs in California on January 1, 2013.

[209] The law also set some explicit requirements, such as requirements for development of new renewable generating capacity and requirements to phase out older coal-fired EGUs.

[210] See State of Colorado House Bill 10–1365, available at *http://www.leg.state.co.us/clics/clics2010a/csl.nsf/fsbillcont/0CA296732C8CEF4D872576E400641B74?Open&file=1365_ren.pdf.*

[211] Participating states include Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont.

[212] See RGGI Web site at *http://www.rggi.org/rggi.*

[213] Potential heat rate improvements create opportunities for EGU owners to reduce their variable costs, which increase potential operating profits from generation and thereby create opportunities to lower the prices at which the owners would bid the capacity of their EGUs into the auctions.

undertake to achieve heat rate improvements are technically feasible and of reasonable cost, and meet the other requirements to qualify as a component of the ''best system of emission reduction . . . adequately demonstrated.''

The EPA's analysis and conclusions regarding the technical feasibility, costs, and magnitude of CO_2 emission reductions achievable through heat rate improvements are discussed in Section VI.C.1 above. We consider heat rate improvement to be a common and well-established practice within the industry.

Other BSER criteria also favor building block 1 as a component of the BSER. For example, with respect to non-air health and environmental impacts, heat rate improvements cause fuel to be used more efficiently, reducing the volumes of and therefore the adverse impacts associated with disposal of coal combustion solid waste products. With respect to technological innovation, building block 1 encourages the spread of more advanced technology to EGUs currently using components with older designs. The EPA has not specifically evaluated the extent to which enhanced maintenance practices leading to heat rate improvements might also lead to electricity reliability improvements, but generally expects that enhanced maintenance would be more likely to improve than to degrade EGU availability, which would tend to improve electricity system reliability.

As noted above, the EPA is concerned about the potential ''rebound effect'' associated with building block 1 if applied in isolation. More specifically, we noted that in the context of the integrated electricity system, absent other incentives to reduce generation and CO_2 emissions from coal-fired EGUs, heat rate improvements and consequent variable cost reductions at those EGUs would cause them to become more competitive compared to other EGUs and increase their generation, leading to smaller overall reductions in CO_2 emissions (depending on the CO_2 emission rates of the displaced generating capacity). However, we believe that this concern can be readily addressed by ensuring that the BSER also reflects other CO_2 reduction strategies that encourage increases in generation from lower- or zero-carbon EGUs or in demand-side energy efficiency, thereby allowing building block 1 to be considered part of the BSER for CO_2 emissions at affected EGUs.

b. Building Block 2—Re-Dispatch

Building block 2—reducing CO_2 emissions at and substituting for generation from the most carbon-intensive affected EGUs with generation from less carbon-intensive affected EGUs (specifically NGCC units that are currently operating or under construction)—is a component of the BSER because the shifts in generation that it involves demonstrate that reducing mass CO_2 emissions at higher-emitting EGUs is technically feasible, will not jeopardize system reliability, is of reasonable cost, and meets the other requirements for a component of the ''best system of emission reduction . . . adequately demonstrated.''

The EPA's analysis and conclusions regarding the technical feasibility, costs, and magnitude of CO_2 emission reductions achievable at high-emitting EGUs through re-dispatch among affected EGUs are discussed in Section VI.C.2 above. We consider re-dispatch among the large number of diverse EGUs that are linked to one another and to customers by extensive regional transmission grids to be a routine and well-established operating practice within the industry that is used to facilitate the achievement of a wide variety of objectives, including environmental objectives, while meeting the demand for electricity services. As discussed above, in the interconnected and integrated electricity industry, fossil fuel-fired steam EGUs are able to reduce their generation and NGCC units are able to increase their generation in a coordinated manner through mechanisms—in some cases centralized and in others not—that regularly deal with such changes on both a short-term and a longer-term basis.

Both the achievability of this building block and the reasonableness of its costs are supported by the fact that there has been a long-term trend in the industry away from coal-fired generation and toward NGCC generation for a variety of reasons. As part of their CO_2 reduction strategies, states can encourage this trend in a variety of ways. First, a state could use its permitting authority to impose limits on the hours of operation (or emissions) of individual steam generating units over a given time period. Second, a state could change the relative costs of generation for more carbon-intensive and less carbon-intensive generating units by imposing a cost on carbon emissions. A state could do so through any of several market-based mechanisms. One would be to adopt an allowance-based system. An example is the Regional Greenhouse Gas Initiative, an allowance-based system in which sources purchase allowances in periodic auctions. Another way would be through a tradable emission rate system, under which the state would impose an emission rate limit on the steam generating unit that the unit could meet only by purchasing the right to average its emission rate with a unit with a lower rate, such as an NGCC unit. Most broadly, an allowance system would provide the greatest incentive for the most carbon-intensive affected sources to reduce emissions as much as possible so as to reduce their need to purchase allowances (or to allow them to sell un-needed allowances), and the same would be true for a tradable emission rate system.

The emission reductions achievable or supported by the application of building block 2 also perform well against other BSER criteria. For example, we expect that building block 2 would have positive non-air health and environmental impacts. Coal combustion for electricity generation produces large volumes of solid wastes that require disposal, with some potential for adverse environmental impacts; these wastes are not produced by natural gas combustion. The intake and discharge of water for cooling at many EGUs also carries some potential for adverse environmental impacts; NGCC units generally require less cooling water than steam EGUs.[214] As already noted, with respect to energy impacts, the EPA believes that building block 2 (at least at the level of stringency proposed for purposes of establishing state goals) would not pose risks to reliability. Building block 2 also promotes greater use of the advanced NGCC technology installed in the existing fleet of NGCC units.

It should be observed that, by definition of the elements of this building block, the shifts in generation taking place under building block 2 occur entirely among existing EGUs subject to this rulemaking.[215] Through application of this building block considered in isolation, some affected sources—mostly coal-fired steam EGUs—would reduce their generation and CO_2 emissions, while other affected sources—NGCC units—would increase their generation and CO_2 emissions.[216]

[214] According to a DOE/NETL study, the relative amount of water consumption for a new pulverized coal plant is 2.5 times the consumption for a new NGCC unit of similar size. ''Cost and Performance Baseline for Fossil Energy Plants: Volume 1: Bituminous Coal and Natural Gas to Electricity,'' Rev 2a, September 2013, National Energy Technology Laboratory Report DOE/NETL–2010/1397.

[215] For purposes of this rulemaking, ''existing'' EGUs include units under construction as of January 8, 2014, the date of publication in the **Federal Register** of the Carbon Pollution Standards for new fossil fuel-fired EGUs.

[216] Because building blocks 3 and 4 reduce generation and CO_2 emissions from all fossil fuel-

However, because for each MWh of generation, NGCC units produce less CO_2 emissions than coal-fired steam EGUs, the total quantity of CO_2 emissions from all affected sources in aggregate would decrease. In the context of the integrated electricity system, where the operation of affected EGUs of multiple types is routinely coordinated to provide a fungible service, and in the context of CO_2 emissions, where location is a less important factor than is the case for other pollutants, the EPA believes that a measure that takes advantage of that integration to reduce CO_2 emissions from the overall set of affected EGUs is readily encompassed within the meaning of a ''system of emission reduction'' for CO_2 emissions at affected EGUs even if the measure would increase CO_2 emissions from a subset of those affected EGUs. Indeed, our review of the data and discussions with states reveal that some states are already moving in this direction for this purpose (while others are moving in the same direction for other purposes). Emission trading or averaging approaches can facilitate the implementation of such a ''system'' and have already been used in the electricity industry to address CO_2 as well as other pollutants, as discussed above.

Finally, the EPA notes that the alternative interpretation of the BSER discussed later is based in part on the re-dispatch measures in building block 2. In this alternative, as it relates to building block 2, reduced generation from the subset of affected EGUs consisting of fossil fuel-fired steam EGUs—i.e., the most carbon-intensive subset of affected EGUs—is a component of the BSER. The potential to use increased generation from less carbon-intensive affected NGCC units would serve as a basis for quantifying the amounts of generation reductions and CO_2 emission reductions at more carbon-intensive affected EGUs that could be achieved while continuing to meet the demand for electricity services in a reliable and affordable manner. This alternative is discussed further in Section VI.E.7 below.

c. Building Block 3—Use of Expanded Low- and Zero-Carbon Generating Capacity

Building block 3—reducing CO_2 emissions at and substituting for generation from affected EGUs by using expanded amounts of low- and zero-carbon generating capacity—is a component of the BSER because the expansion and use of renewable generating capacity, completion and use of nuclear capacity currently under construction, and avoidance of nuclear capacity retirements all establish the foundation for a determination that mass emission reductions from affected EGUs are technically feasible, do not jeopardize system reliability, are of reasonable cost, and meet the other requirements for a component of the ''best system of emission reduction . . . adequately demonstrated.''

The EPA's analysis and conclusions regarding the technical feasibility, costs, and magnitude of the measures in building block 3 are discussed in Section VI.C.3 above. We consider all of these measures to be proven, well-established practices within the industry, and development of renewable capacity in particular is consistent with recent industry trends. States are already pursuing policies that encourage production of greater amounts of renewable energy, such as the establishment of targets for procurement of renewable generating capacity. Moreover, markets for renewable energy certificates, which facilitate investment in renewable energy, are already well-established. As noted above with re-dispatch, an allowance system or tradable emission rate system would provide incentives for sources to reduce their emissions as much as possible, including through substituting for their generation with generation from renewable energy. In addition, owners of existing nuclear units and nuclear units currently under construction can take action to complete or preserve that capacity, the generation from which likewise can be dispatched in a coordinated manner to substitute for fossil fuel-fired generation. As discussed above, coordination of these decisions in the integrated electricity system can occur through a variety of mechanisms, some centralized and some not.

The renewable capacity measures in building block 3 generally perform well against other BSER criteria. For example, incentives for expansion of renewable capacity encourage technological innovation in improved renewable technologies as well as more extensive deployment of current advanced technologies. Generation from wind turbines (the most common renewable technology) does not produce solid waste or require cooling water, a better environmental outcome than if that amount of generation had instead been produced at a typical range of fossil fuel-fired EGUs. Although the intermittent nature of generation from renewable resources such as wind and solar units requires special consideration from grid operators, renewable generation has grown quickly in recent years, as discussed above, and the EPA has seen no evidence that operators will be less able to cope with future growth than they have with rapid past growth.

The EPA believes that the performance of the nuclear measures in building block 3 against the other BSER measures is also positive on balance. With respect to encouragement of technological innovation, incentives for completion of nuclear capacity currently under construction encourage deployment of nuclear unit designs that reflect advances over earlier designs. The nation's nuclear fleet today routinely operates at high average utilization rates, suggesting no reason to expect adverse reliability consequences from completion or preservation of additional nuclear capacity. The five nuclear units currently under construction are all designed to use closed-cycle cooling systems with lower cooling water usage than some existing fossil fuel-fired EGUs;[217] existing nuclear units may use amounts of cooling water comparable to the amounts used by those fossil fuel-fired steam EGUs. The EPA recognizes that nuclear generation poses unique waste disposal issues (although it avoids the solid waste issues specific to coal-fired generation). However, we do not consider that potential disadvantage of nuclear generation relative to fossil fuel-fired generation as outweighing nuclear generation's other advantages as an element of building block 3. For all these reasons, we consider building block 3 to be a component of the ''best system of emission reduction . . . adequately demonstrated.''

Finally, the EPA notes that the alternative BSER discussed later would include a component consisting of reduced generation from affected EGUs,

fired affected EGUs as a group, including NGCC units, the increase in generation and CO_2 emissions from NGCC units under building block 2 is mitigated to some extent by including those building blocks in the BSER along with building block 2.

[217] *See* U.S. NRC, Watts Bar Unit 2 Final Environmental Statement, Final Report at 3–3, available at *http://pbadupws.nrc.gov/docs/ML1314/ML13144A092.pdf;* U.S. NRC, Summer Units 2–3 Final Environmental Impact Statement, Final Report at 3–14, available at *http://pbadupws.nrc.gov/docs/ML1109/ML11098A044.pdf*; U.S. NRC, Vogtle Units 3–4 Final Environmental Impact Statement, Final Report at 3–5, available at *http://pbadupws.nrc.gov/docs/ML0822/ML082240145.pdf.* Relative to the once-through systems at many existing power plants, closed-cycle cooling systems withdraw from and discharge to external water bodies substantially less overall cooling water, although they also consume larger amounts of water through evaporation. *See* Department of Energy/Office of Fossil Energy's Power Plant Water Management R&D Program, available at *http://www.netl.doe.gov/File%20Library/Research/Energy%20Analysis/Publications/PowerPlantWaterMgtR-D-Final-1.pdf.*

with the measures in building block 3 serving as a basis for quantifying the amount of reduced generation and consequent CO_2 emission reductions. Because of the availability of those measures, the amount of reduced generation can be achieved while continuing to meet the demand for electricity services in a reliable and affordable manner. This alternative BSER is discussed in Section VI.E.7 below.

d. Building Block 4—Increased Demand-Side Energy Efficiency

Building block 4—reducing CO_2 emissions at and reducing generation from affected EGUs by promoting demand-side energy efficiency that reduces the amount of generation required from affected EGUs—is a component of the BSER because the demand-side energy efficiency is technically feasible and of reasonable cost, and meets the other requirements for a component of the ''best system of emission reduction . . . adequately demonstrated.''

The EPA's analysis and conclusions regarding the technical feasibility, costs, and magnitude of building block 4 are discussed in Section VI.C.4 above. We consider demand-side energy efficiency programs to be proven, well-established practices within the industry that are consistent with industry trends. Greater demand-side energy efficiency is already a common policy goal among states, and most states already authorize or require implementation of demand-side energy efficiency programs. Fossil fuel-fired EGUs can reduce their generation. Owners of affected EGUs as well as other parties can contract for demand-side energy efficiency. As discussed above, coordination of these decisions in the integrated electricity system can occur through a variety of mechanisms, some centralized and some not. For example, an allowance system or tradable emission rate system would provide incentives that promote the measures in building block 4 in the same manner as discussed above for other building blocks.

Building block 4 is also very attractive under other BSER criteria. Demand-side energy efficiency avoids the non-air health and environmental effects of the fossil fuel-fired generation for which it substitutes. Further, by reducing the overall amount of electricity that needs to be transmitted between EGUs and customers, demand-side energy efficiency tends to relieve stress on the grid, thereby increasing system reliability. Creating incentives for additional demand-side energy efficiency is also consistent with the goals of encouraging technological innovation in energy efficiency and encouraging deployment of current advanced technologies. For all these reasons, the measures in building block 4 qualify as a component of the ''best system of emission reduction . . . adequately demonstrated.''

The EPA notes that the alternative BSER discussed later would include a component consisting of reduced generation from affected EGUs, with demand-side energy efficiency serving as a basis for quantifying the amounts of generation reductions and consequent CO_2 emission reductions that can be achieved while continuing to meet the demand for electricity services in a reliable and affordable manner. This alternate interpretation of the BSER is discussed in Section VI.E.7 below.

5. Evaluation of Building Block Combinations Against the BSER Criteria

a. Combination of Building Blocks 1 and 2

The EPA has considered whether a combination of building blocks 1 and 2 would be the BSER. As described in Section VI.D above, we believe that such a combination is technically feasible and would be a ''system of emission reduction'' capable of achieving meaningful reductions in CO_2 emissions from affected EGUs at a reasonable cost. The combination would also satisfy other BSER criteria. Nevertheless, we do not propose that this combination should be the BSER because the proposed combination of all four building blocks is capable of achieving greater reductions in CO_2 emissions from affected EGUs at a lower cost.

The EPA believes that both building blocks 1 and 2 individually satisfy the BSER criteria identified by the statute and the D.C. Circuit, with one possible concern, related to a ''rebound effect,'' noted earlier. That concern is the potential for the heat rate improvements in building block 1, if implemented in isolation, to make coal-fired steam EGUs more competitive compared to other EGUs and cause them to increase their generation, creating a ''rebound effect'' that would make building block 1 less effective at reducing CO_2 emissions. As discussed above, building blocks 1 and 2 each appear attractive or neutral with respect to each of the other BSER criteria.

With respect to most of the BSER criteria, there is no reason to expect that the combination of building blocks 1 and 2 would be evaluated differently from the individual building blocks. However, as noted earlier, the combination addresses the concern about building block 1 regarding a potential rebound effect, and in that important respect it performs better than building block 1 considered in isolation. The substitution of NGCC generation for generation from coal-fired and other steam EGUs ensures that generation from coal-fired EGUs, as a group, would not increase as a result of their improved variable costs, with the result that the reduction in CO_2 emission rates of coal-fired EGUs brought about by heat rate improvements would not be offset by an increase in CO_2 emissions due to increased generation from those EGUs. The combination of building blocks would therefore be capable of achieving greater reductions in CO_2 emissions from affected sources than either building block in isolation.

While achieving substantially greater emission reductions than building block 1 alone, by reducing overall generation from coal-fired EGUs the combination of building blocks 1 and 2 also has the potential to raise the cost of the portion of the overall emission reductions achievable through heat rate improvements relative to the cost of those reductions if building block 1 were implemented in isolation.[218] However, the EPA believes that the cost of emission reductions achieved through heat rate improvements would remain reasonable for two reasons. First, as discussed in Section VI.C.1 above, the cost of CO_2 emission reductions achievable through heat rate improvements is quite low, and that cost would remain reasonable even if it was substantially increased. Second, although under the combination of building blocks 1 and 2 the volume of coal-fired generation would decrease, that decrease is unlikely to be spread uniformly among all coal-fired EGUs. It is more likely that some coal-fired EGUs would decrease their generation slightly while others would decrease their generation by larger percentages or cease operations altogether. We would expect EGU owners to take these changes in EGU operating patterns into account when considering where to invest in heat rate improvements, with the result that there would be a tendency for such investments to be concentrated in EGUs whose generation output was expected to decrease the

[218] If an EGU produces less generation output, then an improvement in that EGU's heat rate and rate of CO_2 emissions per unit of generation produces a smaller reduction in CO_2 emissions. If the investment required to achieve the improvement in heat rate and emission rate is the same regardless of the EGU's generation output, then the cost per unit of CO_2 emission reduction will be higher when the EGU's generation output is lower.

least. This enlightened bias in spending on heat rate improvements—that is, focusing investments on EGUs where such improvements would have the largest impacts and produce the highest returns, given consideration of projected changes in dispatch patterns—would tend to mitigate any deterioration in the cost of CO_2 emission reductions achievable through heat rate improvements.

As noted above, the EPA invites comment on a potential BSER comprising building blocks 1 and 2, in light of the considerations that could support this approach.

b. Combination of All Four Building Blocks

The EPA's proposed BSER is a combination of all four building blocks. For the reasons described below, and similar to each of the building blocks, the combination must be considered a ''system of emission reduction.'' Moreover, as also discussed below, the combination qualifies as the ''best'' system that is ''adequately demonstrated.'' The combination is technically feasible; it is capable of achieving meaningful reductions in CO_2 emissions from affected EGUs at a reasonable cost; it satisfies the other BSER criteria as well; and its components are well-established. The combination of all four building blocks would achieve greater CO_2 emission reductions at a lower cost than the combination of building blocks 1 and 2 described above, and would also perform better against other BSER criteria. We therefore propose to find the combination of all four building blocks to be the ''best system of emission reduction . . . adequately demonstrated'' for reducing CO emissions at affected EGUs.[219]

The assessments of the individual building blocks against the BSER criteria would generally apply in the same way to those building blocks when implemented as the combination of all four building blocks, with the same exceptions as discussed above with respect to the combination of building blocks 1 and 2 as well. However, the combination of all four building blocks would improve upon the combination of building blocks 1 and 2 in several respects. First, because of the potential of building blocks 3 and 4 to achieve additional CO_2 reductions at reasonable costs, the broader combination would achieve greater CO_2 emission reductions at a lower average cost. Second, by encompassing the increased low-and zero-carbon generation in building block 3, the broader combination would reduce reliance on fossil fuels and improve fuel diversity. Third, by encompassing the increased demand-side energy efficiency in building block 4, the broader combination would reduce the amount of electricity that would need to be delivered over the electric grid, generally reducing pressure on the grid and thereby improving electricity system reliability. These considerations all support basing the BSER on the combination of all four building blocks. They also support basing the BSER, in the alternative, on the combination of building block 1 and reduced generation in the amounts facilitated by the remaining building blocks.

As has been discussed in earlier portions of the preamble, the costs and energy impacts of each of the four building blocks individually are reasonable when viewed either at the individual source level or through the lens of the electricity system as a whole, a conclusion that holds for the combination of the building blocks as well. Moreover, the flexibility available to states and regulated entities to rely more extensively in their plans and strategies on whichever measures best suit their particular circumstances will further improve cost effectiveness. The analysis the EPA performed to assess the costs, benefits, and other impacts of the proposed goals reflects this compliance flexibility, along with transmission and pipeline capabilities and constraints, fuel market and electricity dispatch dynamics, and seasonal electricity load requirements. As described below in Section X, the results indicate that the proposed state goals (discussed in Section VII) are readily achievable with no adverse impacts on electricity system reliability, and that impacts on retail electricity prices are modest and fall within the range of price variability seen historically in response to changes in factors such as weather and fuel supply. Further, the costs tend to decline over time as states and regulated entities take advantage of the available flexibility and expand deployment of more cost-effective measures (notably demand-side energy efficiency). The EPA considers this analysis strong confirmation of the reasonableness of the costs of the measures in the four building blocks in combination as the best system of emission reduction.

[219] The analysis of the interactions among building blocks provided above for the combination of building blocks 1 and 2, indicating that the addition of building block 2 would mitigate the potential concern about a ''rebound effect'' if building block 1 were implemented in isolation, applies to the combination of all four building blocks as well; in fact, the addition of building blocks 3 and 4 would further mitigate that concern. The EPA believes that if implemented in combination, each of the four building blocks would achieve substantial reductions in CO_2 emissions from affected EGUs at a reasonable cost.

6. Additional Considerations Related to Inclusion of Building Blocks 2, 3, and 4 as Part of the Basis Supporting the BSER

In this section, we discuss additional reasons why the measures in building blocks 2, 3, and 4, individually and in combination, meet the requirements to be components of the BSER. In particular, we discuss why they meet the definition of a ''system of emission reduction,'' and we provide additional reasons why they are the ''best'' that is ''adequately demonstrated.'' The interconnected nature of the electric system is an important part of our reasoning.

a. ''System of Emission Reduction''

For the convenience of the reader, it is useful to reiterate the key CAA section 111 requirements: Section 111(d)(1) requires that each state's plan ''establish[] standards of performance for any existing source'' for certain types of air pollutants; and section 111(a)(1) defines a ''standard of performance'' as ''a standard for emissions . . . which reflects the degree of emission limitation achievable through the application of the best system of emission reduction . . . adequately demonstrated.'' These provisions require that, in this rulemaking, the affected sources must be subject to emissions standards, but the basis for those standards—the ''system of emission reduction''—may be any method that reduces the affected sources' emissions, as long as that method is a ''system'' that meets the criteria for being the ''best'' that is ''adequately demonstrated.''

As discussed in the Legal Memorandum, the EPA is justified in adopting this interpretation under the first step of the framework for administrative agencies to construe statutes that the U.S. Supreme Court established in *Chevron U.S.A. Inc.* v. *NRDC,* 467 U.S. 837, 842–844 (1984) (*Chevron*), which we refer to as *Chevron* step 1.

Specifically, the term ''system,'' which is not defined in the CAA, is broad: ''A set of things working together as parts of a mechanism or interconnecting network.'' [220] The

[220] *Oxford Dictionary of English* (3rd ed.) (published 2010, online version 2013), *http://www.oxfordreference.com.mutex.gmu.edu/view/10.1093/acref/9780199571123.001.0001/acref-9780199571123.*

remaining provisions of the definition of ''standard of performance'' do not include any constraints on the ''set of things'' that may constitute a ''system of emission reduction.'' Nor does the context in which ''standard of performance'' is found—the provisions of section 111(d)(1)—add constraints on the things that may constitute such a system. Rather, it is clear from these CAA provisions that anything that reduces the emissions of affected sources may be considered a ''system of emission reduction'' for those sources. For this reason, the measures in building blocks 2, 3, and 4 must be considered components of such a system.

Even if these CAA provisions leave room for interpretation as to whether those measures must be considered components of such a system, the EPA's interpretation that they do is reasonable. As discussed in the Legal Memorandum, the EPA is justified in adopting this interpretation under the second step of the *Chevron* framework, which we refer to as *Chevron* step 2. There are several reasons. In enacting the CAA, Congress established ''pollution prevention'' as a ''primary goal'' of the Act, and described it as ''the reduction or elimination, through any measures, of the amount of pollutants produced or created at the source.'' [221] Building blocks 2, 3, and 4 are pollution prevention measures, and, in light of the importance of pollution prevention in the CAA, it is reasonable to interpret ''system of emission reduction'' in section 111 to incorporate those measures. In addition, the breadth of ''system of emission reduction'' is confirmed by contrasting it with other provisions in the CAA that prescribe specific types of controls as the basis for emission limits.[222] Further support is found in Title IV of the CAA, in which Congress established the program that regulates fossil fuel-fired power plants to reduce their emissions of SO_2 and NO_X, the precursors to acid deposition. In designing Title IV, Congress recognized the integrated nature of the electricity sector and how that integration could be harnessed to reduce air pollutant emissions. In fact, Congress included provisions to encourage re-dispatch to lower-emitting sources, renewable energy, and demand-side energy efficiency, all of which are measures in those building blocks.[223] All this supports the reasonableness of interpreting ''system of emission reduction'' in CAA section 111 to incorporate those measures. It should also be noted that a number of commentators in the private sector and academia have indicated support for interpreting the term, ''system of emission reduction'' to base the CAA section 111(d) standards of performance on measures such as re-dispatch, renewable energy, and demand-side energy efficiency.[224] Some stakeholders have as well.[225]

b. ''Best'' System That Is ''Adequately Demonstrated

As described earlier with respect to the individual building blocks, the measures in each of building blocks 2, 3, and 4 meet the criteria for the ''best'' system of emission reduction, and, generally for the same reasons, the three in combination do as well.

In addition, the measures in building blocks 2, 3, and 4, individually and in combination, are ''adequately demonstrated.'' As discussed earlier, thanks to the integrated nature of the electricity system, they have long been relied on to reduce costs in general, assure reliability, and implement pre-existing pollution control requirements in the least-cost manner. As also noted elsewhere in the preamble, and discussed in more detail in the following subsections, some utilities, states and regions are already relying on these measures for the specific purpose of reducing CO_2 emissions from EGUs.

(i) Actions by Affected EGUs

Measures in building blocks 2, 3, and 4 may be undertaken or invested in by the affected EGUs themselves, which supports that these measures are ''adequately demonstrated.'' More specifically, the EPA believes that owners of units operating across a wide range of corporate, institutional and market structures (e.g., vertically integrated utilities in regulated markets, independent power producers, municipal utilities, and rural cooperatives) can take advantage of a broad range of reduction opportunities included in the building blocks. Because of the proposed lengthy planning period, owners can consider longer-term options such as implementing energy efficiency programs or replacement of older generating resources with more modern types of generation, as well as shorter-term options such as heat rate improvements and re-dispatch. Many companies, for example, already factor a carbon cost adder into their long-term planning decisions.

Large vertically integrated utilities generally have options within all four building blocks. They tend to have large and, as a general matter, at least somewhat diverse generation fleets. For their higher-emitting units, they have opportunities to use measures that reduce the units' CO_2 emission rates, such as heat rate improvements, co-firing, or fuel switching. While this proposal preserves fuel diversity, with over 30 percent of projected 2030 generation coming from coal and over 30 percent from natural gas, even companies that have traditionally depended upon coal to supply the majority of their generation are diversifying their fleets, increasing their

[221] CAA § 101(a)(3), (c).

[222] For example, as discussed in the Legal Memorandum, CAA § 407(b)(2) requires the EPA to base the nitrogen oxides (NO_X) emission limits for certain types of boilers ''on the degree of reduction achievable through the *retrofit* application of the best system of continuous emission reduction . . . ;'' and further requires the EPA to revise previously promulgated emission limits for certain types of boilers ''to be more stringent if the [EPA] determines that *more effective low NO_X burner technology* is available.'' (Emphasis added.)

[223] CAA § 401(b), 404(f)–(g).

[224] *See* Nordhaus R., Gutherz I., ''Regulation of CO_2 Emissions from Existing Power Plants Under § 111(d) of the Clean Air Act: Program Design and Statutory Authority,'' *Environmental Law Reporter,* 44: 10366, 10384 (May 2014) (''strong arguments for'' interpreting ''system'' to include measures such as the addition of new zero-carbon generating capacity and increases in end-user energy efficiency); Sussman R., ''Power Plant Regulation Under the Clean Air Act: A Breakthrough Moment for U.S. Climate Policy?'' *Virginia Environment Law Journal,* 32:97, 119 (2014) (''EPA would seem to have discretion to define 'system' to include any mix of strategies effective in reducing emissions.''); Konschnik K., Peskoe A., ''Efficiency Rules: The Case for End-Use Energy Efficiency Programs in the Section 111(d) Rule for Existing Power Plants,'' *Harvard Law School Environmental Law Program—Policy Initiative* 4 (March 3, 2014) (EPA is authorized to ''consider[ ] . . . the entire [electricity grid] system when setting performance standards.''); Monast J., Profeta T., Pearson B., Doyle J., ''Regulating Greenhouse Gas Emissions From Existing Sources: Section 111(d) and State Equivalency,'' Environmental Law Reporter, 42: 10206, 10209 (March 2012) (''Demand-side energy-efficiency programs and renewable energy generation may fit within the § 111 framework, however, because both reduce the utilization of power plant. . . . According to this reasoning, emission reductions are occurring within the source category, because of changes in generation at the power plant.'').

[225] Ceronsky M., Carbonell T., ''Section 111(d) of the Clean Air Act: The Legal Foundation for Strong, Flexible & Cost-Effective Carbon Pollution Standards for Existing Power Plants,'' *Environmental Defense Fund,* at 9 (Oct. 2013), *available at http://www.edf.org/sites/default/files/111-clean_air_act-strong_flexible_cost-effective_carbon_pollution_standards_for_existing_power_plants.pdf*; Doniger D., ''Questions and Answers on the EPA's Legal Authority to Set 'System Based' Carbon Pollution Standards for Existing Power Plants under Clean Air Act Section 111(d),'' *NRDC [Natural Resources Defense Council] Issue Brief* (Oct. 2013); ''Comments of the Attorneys General of New York, California, Massachusetts, Connecticut, Delaware, Maine, Maryland, New Mexico, Oregon, Rhode Island, Vermont, Washington, and the District of Columbia on the Design of a Program to Reduce Carbon Pollution from Existing Power Plants'' (Dec. 16, 2013).

opportunities for re-dispatch.[226] Within the 5-to-15-year planning horizon established in this proposal to begin in June 2015, most of these companies are likely to be investing in new generation and can consider options such as increased reliance on new renewable generating capacity. They also run energy efficiency programs for their customers.

Municipal utilities and rural cooperatives that own generating asset portfolios also have multiple options for reducing CO_2 emissions, particularly generation and transmission cooperatives and larger municipal utilities. They can implement unit-specific improvements, re-dispatch to lower emitting resources, employ energy efficiency and renewable energy strategies, and explore longer-term capacity planning strategies. For cooperatives and municipal utilities with smaller fleets, re-dispatching among their own units may not provide as many opportunities, particularly in the short term. But because of the timing flexibility in the guidelines, these owners can use both short-term dispatch strategies and longer-term capacity planning strategies to reduce GHG emissions, and in many cases financing is available at tax-advantaged or subsidized rates. At the same time, in formulating their plans, states will be in a position to recognize the distinctive attributes of smaller utilities—and, of course, may consider participating in integrated multi-state compliance strategies to increase the flexibility and cost-saving opportunities that would be available to the covered EGUs.

Some stakeholders have expressed concerns that municipal utilities and rural cooperatives can face other challenges as well. According to these stakeholders, in deregulated areas, even though these utilities may be fully vertically integrated entities, they may not have as much flexibility to control dispatch because they are operating in a competitive market, where they can be in a position in which they need to operate if called upon. Even in this case, the timing flexibility of the rule allows them to consider longer-term capacity planning strategies. These can include building or contracting for electric supply from lower-emitting sources, use of distributed renewable technologies, and use of demand-side energy efficiency measures. There are a number of municipal utilities and rural cooperatives that are already aggressively pursuing such strategies.[227] Nevertheless, in recognition of stakeholders' expressed concerns, we invite comment on whether there are special considerations affecting small rural cooperative or municipal utilities that might merit adjustments to this proposal, and if so, possible adjustments that should be considered.

Independent power producers (IPPs) may also face unique challenges but nevertheless have options. Companies with coal-fired EGUs can implement efficiency improvements as well as other unit-level compliance options such as co-firing or fuel switching. While these types of companies do not use the integrated resource planning process that many vertically integrated utilities use, they still undertake long-term business planning and as a result are in a position to consider different long-term strategies related to their generating assets. Many IPPs are actively developing renewable generating capacity and natural gas-fired generating capacity. IPP owners could also fund demand-side energy efficiency programs and document the resulting electricity savings.

(ii) Actions by States

Another reason why the measures in building blocks 2, 3, and 4 are ''adequately demonstrated'' is that states may adopt them and, in fact, many states have already adopted many of them.

For example, several states have already adopted renewable energy (RE) and demand-side energy efficiency (EE) measures in their CAA section 110 state implementation plans (SIPs) for attaining and maintaining the national ambient air quality standards (NAAQS). The EPA has provided initial guidance for states to do so.[228] Some state air agencies did so for their 1997 8-hour ozone NAAQS SIPs that were due in 2007; for example, Washington, DC, included the purchase of wind power and the installation of LED traffic lights[229]; Dallas, Texas included efficiency measures from the Texas Emissions Reduction Program (TERP)[230]; and Connecticut included projects such as high efficiency air conditioners, compact fluorescent lighting, combined heat and power (CHP), and solar photovoltaic installations.[231] Since that time, many states have adopted legislative mandates for energy efficiency or renewable energy, and states have expressed interest in including EE/RE policies and programs in upcoming NAAQS SIPs. The EPA has provided additional guidance[232] and has partnered with the Northeast States for Coordinated Air Use Management (NESCAUM) and three states (Maryland, Massachusetts, and New York) to identify opportunities for including EE/RE in a NAAQS SIP and to provide real-world examples and lessons learned through those states' case studies.[233]

It should be recognized that each state's electric utility sector operates under distinctive conditions and circumstances. The EPA's proposal ensures that states retain flexibility to craft standards of performance that can accommodate characteristics including fuel sources, types of EGU owners within a state (e.g., investor-owned, municipal, and cooperative utilities, and independent power producers), and regulatory structure (e.g., regulated or restructured). States can tailor their regulatory mechanisms to recognize differences, for example by creating budgets on a company-wide basis or using market-based mechanisms such as mass-based trading systems, to ensure that requirements are achievable.

The proposal also recognizes that states have different resource bases and energy policies in place, and these differences are taken into account in the state goal-setting and computation process. For instance, while the EPA's BSER assumptions consider re-dispatch to NGCC units, they do not consider re-dispatch beyond the NGCC capacity already existing in a state. In that way, the proposal does not presume that

[226] *http://online.wsj.com/article/PR-;CO-20140508-;915605.html*.

[227] For examples, see Large Public Power Council, Energy Efficiency Working Group, Second Annual Energy Efficiency Benchmarking Report (2013); *https://www.nreca.coop/nreca-on-the-issues/energy-operations/energy-efficiency/*.

[228] *See, e.g.,* Guidance on SIP Credits for Emission Reductions from Electric-Sector Energy Efficiency and Renewable Energy Measures (Aug. 2004), *http://www.epa.gov/ttn/oarpg/t1/memoranda/ereseerem_gd.pdf;* Incorporating Emerging and Voluntary Measures in a State Implementation Plan (SIP) (Sept. 2004), *http://www.epa.gov/ttn/oarpg/t1/memoranda/evm_ievm_g.pdf*.

[229] DC Region 8-hour ozone SIP at 126, *http://www.mwcog.org/uploads/pub-documents/9FhcXg20070525084306.pdf*.

[230] Dallas/Ft. Worth, Texas 8-hour ozone SIP, *http://www.gpo.gov/fdsys/pkg/FR-2008-08-15/pdf/E8-18835.pdf*.

[231] CT 1997 8-hour ozone SIP Web site, *http://www.ct.gov/deep/cwp/view.asp?a=2684&q=385886&depNav_GID=1619* (see Attainment Demonstration TSD, Chapter 8 at 31, *http://www.ct.gov/deep/lib/deep/air/regulations/proposed_and_reports/section_8.pdf*).

[232] Roadmap for Incorporating EE/RE Policies and Programs into SIPs/TIPs (July 2012), *http://epa.gov/airquality/eere/manual.html*.

[233] States' Perspectives on EPA's Roadmap to Incorporate Energy Efficiency/Renewable Energy in NAAQS State Implementation Plans: Three Case Studies, Final Report to the U.S. Environmental Protection Agency (Dec. 2013), *http://www.nescaum.org/documents/nescaum-final-rept-to-epa-ee-in-naaqs-sip-roadmap-case-studies-20140522.pdf*.

states with limited natural gas generation or infrastructure will have to develop those resources.

Furthermore, while the BSER reflects best practices for both renewables and energy efficiency, it also recognizes that some states have made more progress than others in these areas. The BSER allows time for states to ramp up to greater levels of energy efficiency and use and development of renewable energy resources, should they choose those approaches. With respect to renewable energy, the proposal also recognizes that different areas of the country have different resource bases and does not presume that a uniform level of penetration of renewable generation is appropriate for every state.

The features provided in this proposal to ensure policy flexibility can be used by all states to address their unique circumstances. In a regulated state, if a company's compliance strategies included reducing generation at higher-emitting EGUs, it would work through its state's integrated planning process to ensure that adequate generation was available through a combination of all four building blocks. Cost recovery, and cost oversight, can be achieved through rate cases before state regulators. In a restructured state, even if affected companies responded to the guidelines by reducing generation without themselves replacing that generation, the electricity markets that have developed would react to ensure the availability of replacement generation. Other companies would see opportunities to build or ramp up existing lower-emitting generation, and in some markets that treat demand-side resources on par with supply side resources, energy service companies would likely see opportunities. Further, state regulators can continue to play an important role in restructured states as well, authorizing or reviewing both renewable energy procurement and demand-side energy efficiency programs. In all types of market structures, large energy users might independently see additional energy efficiency opportunities or opportunities for self-generation using options such as combined heat and power, solar, or power purchase agreements, and states can structure their plans to allow the CO_2 reductions achieved at affected EGUs through such actions to assist in reaching compliance. As discussed in earlier portions of this section and elsewhere in the preamble, each of the building blocks is already being widely implemented, is consistent with industry trends, and consists of CO_2 reduction methods already widely accepted in the eyes of various stakeholders, as was clear from views expressed in our outreach process.

Moreover, there are mechanisms through which states could require measures from any of the building blocks in state plans. In fact, the state plan formulation process through which CAA section 111(d) is implemented reinforces the determination that these measures are components of the BSER. For example, states would have authority to impose measures such as best practices for operation and maintenance of EGUs, dispatch limits, renewable energy resource requirements, and demand-side energy efficiency requirements. States also would have authority to establish requirements that change the relative costs of generation from more carbon-intensive and less carbon-intensive EGUs, for example by creating emission allowance systems that cause market participants and system operators to take account of CO_2 emission rates as an element of variable operating costs. Such an approach can encourage measures from all of the building blocks simultaneously. As noted elsewhere in the preamble, many states have already pursued one or more of these approaches.[234]

It also should be noted that during the public outreach sessions, stakeholders generally recommended that state plans be authorized to rely on, and that affected sources be authorized to implement, re-dispatch, renewable energy measures, and demand-side energy efficiency measures in order to meet states' and sources' emission reduction obligations. The EPA agrees that state plans may include these measures, at least under certain circumstances, as discussed in Section VIII, and that sources may rely on them to achieve required reductions. It is clear that these types of measures are well-accepted by the stakeholders as means to reduce emissions from affected sources. The fact that state plans and sources would be expected to use these types of measures to reduce emissions supports the view that these measures are part of a ''system of emission reduction'' for those sources that the EPA may evaluate against the appropriate criteria to determine whether they comprise the ''best system of emission reduction . . . adequately demonstrated.''

(iii) Regional Organizations

Another reason why the measures in building blocks 2, 3, and 4 are ''adequately demonstrated'' is that they can be accommodated through the existing regional components of the electricity system.

On the regional level, ISO/RTOs control dispatch and are responsible for reliable operation of the bulk power system.[235] They can seek solutions, such as capacity markets and transmission upgrades, to preserve resource adequacy and ensure the continued reliable operation of the grid. For this proposal, the ISO/RTO Council has already submitted a set of recommendations they believe can help balance the needs of lower emissions, economic dispatch, and reliability, which is discussed in greater detail in Section VIII.F.7 of this proposal.[236] For areas of the country that are not covered by an ISO/RTO, there are regional groups, such as ColumbiaGrid, Northern Tier Transmission Group and WestConnect in the west, and system operators such as Southern Company in the southeast, that can provide these functions. In shifting to lower-emitting units, grid operators across the country factor environmental costs into their economic dispatch through a variety of mechanisms, including allowance costs, variable costs associated with operating environmental controls, and operating limits for high-emitting units.

(iv) Concerns From Stakeholders; Solicitation of Comment

We note that some stakeholders have argued that CAA section 111(a)(1) does not authorize the EPA to identify re-dispatch, low- or zero-emitting generation, or demand-side energy efficiency measures (building blocks 2, 3, and 4) as components of the ''best system of emission reduction . . . adequately demonstrated.'' According to these stakeholders, as a legal matter, the BSER is limited to measures that may be undertaken at the affected units, and not measures that are beyond the affected units; the measures in building blocks 2, 3, and 4 are ''beyond-the-unit'' or ''beyond-the-fenceline'' measures because they are implemented outside of the affected units and outside their control; and as a result, those measures cannot be considered components of the BSER.

We welcome comment on this issue. As discussed above, we propose that the

[234] See the discussions of California California Global Warming Solutions Act and RGGI above in this section and elsewhere in the preamble.

[235] Across all markets, at the federal level, FERC and NERC create and oversee standards for reliability. NERC works with electric reliability councils and control areas that comprise all types of utilities and system operators to ensure that adequate generation is available.

[236] *http://www.isorto.org/Documents/Report/20140128_IRCProposal-ReliabilitySafetyValve-RegionalComplianceMeasurement_EPA-C02Rule.pdf.*

provisions of CAA section 111 do not by their terms preclude the BSER from including those types of measures. In addition, as noted above, under our proposed approach, affected sources may themselves implement the measures included in building blocks 2, 3, and 4, so that those measures are within their control with the result of their application being emissions reductions at affected EGUs. Moreover, under our alternative approach, the ''system of emission reduction'' includes reductions in utilization at the affected sources themselves.[237] It should also be noted that, as discussed above, the re-dispatch measures in building block 2 are limited to affected sources. Thus, the proposed approach and alternative described above respond to these stakeholder concerns.

7. Alternate Approach to the Best System of Emission Reduction

As an alternative to the approach described above for determining the ''best system of emission reduction . . . adequately demonstrated,'' the ''system of emission reduction'' may be identified as including, in addition to building block 1, the reduction of affected fossil fuel-fired EGUs' mass emissions achievable through reductions in generation of specified amounts from those EGUs. Under this approach, the measures in building blocks 2, 3, and 4 would not be components of the system of emission reduction but instead would serve as bases for quantifying the reduced generation (and therefore emissions) at affected EGUs, and assuring that the amount of reduced generation meets the criteria for the ''best'' system that is ''adequately demonstrated'' because, among other things, the reduced generation can be achieved while the demand for electricity services can continue to be met in a reliable and affordable manner. Specifically, the amount of generation from the increased utilization of NGCC units would determine a portion of the amount of the generation reduction component of the BSER for affected fossil fuel-fired steam EGUs, and the amount of generation from the use of expanded low- and zero-carbon generating capacity that could be provided, along with the amount of generation from fossil fuel-fired EGUs that could be avoided through the promotion of demand-side energy efficiency, would determine a portion of the amount of the generation reduction component of the BSER for all affected EGUs.

Reduced generation is encompassed by the terms of the phrase ''system of emission reduction'' in CAA section 111(a)(1), as a matter of *Chevron* step 1, because, in accordance with the above-discussed definition of ''system,'' reduced generation is a ''set of things''—which include reduced use of generating equipment and therefore reduced fuel input—that the affected source may take to reduce its CO_2 emissions.[238] If that phrase is not considered clear by its terms, then, under *Chevron* step 2, it may reasonably be interpreted to include reduced generation.[239] As discussed in the Legal Memorandum, the legislative history of the 1970 CAA Amendments indicates that Congress recognized that emitting sources could comply with pollution control requirements by reducing production, including retiring.[240] As also noted in the Legal Memorandum, examples of reduced utilization as a means of reducing emissions are found in settlement agreements between the EPA and fossil fuel-fired EGUs to resolve alleged violations of the CAA new source review (NSR) requirements.[241]

Reduction of, or limitation on, the amount of generation is already a well-established means of reducing emissions of pollutants in the electric sector, notwithstanding the fact that as a practical matter, some facilities may have to operate, or remain available, to ensure system reliability. For example, reduced generation by higher-emitting sources is one of the compliance options available to, and used by, EGUs to comply with the Clean Air Act acid rain program in CAA title IV, as well as the transport rules that we refer to as the NO_X SIP Call[242] and the Clean Air Interstate Rule (CAIR).[243] Reduction in generation is also a possible means by which an EGU can achieve compliance with its requirements under RGGI.

Reduced generation in specified amounts is part of the ''best'' system of emission reduction that is ''adequately demonstrated.'' Reduced generation is technically feasible because of a source's ability to limit its own operations. In addition, the amounts of generation and emission reductions may be determined with precision through the application of building block 2, 3, and 4 measures for increased generation from low- or zero-emitting sources and increased demand-side energy efficiency, which, in turn, ensure the reliability of the electricity grid and the affordability of electricity to businesses and consumers.

Because of the availability of the measures in building blocks 2, 3, and 4, the proposed levels of reduced generation are of reasonable cost for the affected source category and the nationwide electricity system, do not jeopardize reliability, result in an important amount of emission reductions, are consistent with current trends in the electricity sector, and promote the development and implementation of technology that is important for continued emissions reductions. All these results come about because the operation of the electrical

[237] Commenters have critiqued this ''at-the-unit'' and ''beyond-the-unit'' distinction as follows:

There is an argument that the at-the-unit/beyond-the-unit distinction is not a meaningful one. Specifically, it could be argued that the distinction between at-the-unit and beyond-the-unit measures is largely artificial, because all of the emission reductions under consideration—whether from at-the-unit measures (e.g., fuel-switching or efficiency upgrades) or from beyond-the-unit measures—are, in fact, emission reductions at or from electric generating units on the interconnected electric grid. For example, neither the addition of renewable generation nor the reduction of end-user demand directly reduces atmospheric emission of CO_2; rather these measures permit fossil EGUs to reduce their own output and emissions. It can be argued that all of the systems of emission reduction here contemplated—whether they involve end-use energy efficiency, displacing high-emission generation with lower emission generation, fuel-switching, heat-rate improvements, etc.—are effectively at-the-unit measures that ultimately reduce emissions solely from regulated EGUs. If energy-efficiency programs, added renewable energy, and redispatch from higher emitting facilities to lower emitting facilities are viewed as at-the-unit systems of emission reduction, the at-the-unit/beyond-the-unit distinction arguably becomes irrelevant—at least from a legal perspective. Rather, the real issue may come down to whether § 111(d) authorizes the EPA to require EGUs to curtail their output of electricity as a means of complying with the rule.

Nordhaus R., Gutherz I., ''Regulation of CO_2 Emissions from Existing Power Plants Under § 111(d) of the Clean Air Act: Program Design and Statutory Authority,'' *Environmental Law Reporter,* 44: 10366, 10383 n. 133 (May 2014).

[238] For this reason, under a *Chevron* step 1 interpretation, ''system of emission reduction'' includes reduced generation.

[239] For these reasons, under a *Chevron* step 2 interpretation, ''system of emission reduction'' includes reduced generation.

[240] *See* CAA section 110(g) (authorizing temporary emergency suspensions of SIP revisions if needed to prevent the closing of a source of air pollution), enacted as CAA section 110(f) in the 1970 CAA Amendments; 116 Cong. Rec. 42384 (Dec. 18, 1970), *reprinted in* Congressional Research Service, *A Legislative History of the Clean Air Act Amendments of 1970,* vol. 1, at 132–33 (1974) (statement of Sen. Muskie) (discussing criteria for sources to receive compliance date extensions). Sen. Muskie added that the emission standards set by the EPA for hazardous air pollutants ''could include emission standards which allowed for no measureable emissions,'' *id.,* which further suggests that, as a practical matter, the standards could result in reduced production.

[241] *See, e.g.,* Consent Decree at 18, *United States* v. *Wis. Power & Light Co.,* No. 13–cv–266 (W.D. Wis. filed Apr. 22, 2013), *available at http://www2.epa.gov/sites/production/files/documents/wisconsinpower-cd.pdf.*

[242] 63 FR 57356 (Oct. 27, 1998).

[243] 70 FR 25162 (May 12, 2005).

grid through integrated generation, transmission, and distribution networks creates fungibility for electricity and electricity services, which allows decreases in generation at affected fossil fuel-fired steam EGUs to be replaced by increases in generation at affected NGCC units (building block 2) and allows decreases in generation at all affected EGUs to be replaced by increased generation at low- or zero-carbon EGUs (building block 3) or by decreased demand (building block 4). Further, this fungibility increases over longer timeframes with the opportunity to invest in infrastructure improvements, and as noted elsewhere, this proposal provides an extended state plan and source compliance horizon. These characteristics of the integrated electricity system assure that reduced generation in specified amounts meets the criteria to qualify as part of the ''best'' system of emission reduction.

Reduced generation in those amounts is also ''adequately demonstrated.'' As noted above, the measures in building blocks 2, 3, and 4 are already in widespread use in the industry. At the levels proposed, they have the technical capability to substitute for reduced generation at some or all affected EGUs at reasonable cost. The NGCC capacity necessary to accomplish the levels of generation reduction proposed for building block 2 is already in operation or under construction. Moreover, it is reasonable to expect that the incremental resources reflected in building blocks 3 and 4 will develop at the levels requisite to ensure an adequate and reliable supply of electricity at the same time that affected EGUs may choose or be required to reduce their CO_2 emissions by means of reducing their utilization. There are several reasons for this. First, the affected sources themselves could invest in new renewable energy resources and demand-side energy efficiency, as discussed above.[244] Second, the states, as part of their plans, have mechanisms available to put these substitutes in place: They could establish requirements or incentives that would result in new renewable energy and demand-side energy efficiency programs, as also discussed above.[245] Third, as also discussed above, regional entities in the electricity system can accommodate these substitutes.

Most broadly, with respect to the measures in building blocks 2, 3, and 4, provided there is sufficient lead time for planning, mechanisms are in place in both regulated and deregulated electricity markets to assure that substitute generation will become available and/or steps to reduce demand will be taken to compensate for reduced generation by affected EGUs. These mechanisms are based on, among other things, the integrated nature of the electricity system coupled with the availability of capacity in existing NGCC units, the growing institutional capacity of entities that develop renewable energy and demand-side energy efficiency resources, and the ability of system operators and state regulators to incentivize further development of those resources.

The EPA solicits comment on whether measures in addition to those in building blocks 2, 3, and 4 could support the showing that reduced utilization is ''adequately demonstrated,'' including additional NGCC capacity that may be built in the future, as discussed in Section VI.C.5.c above.

8. The EPA's Discretion in Applying the Criteria for the Best System of Emission Reduction

As discussed above, each of the approaches to determining the ''best system of emission reduction . . . adequately demonstrated'' entails applying the criteria described in the D.C. Circuit case law for evaluating the BSER. It should be emphasized that under the case law, the EPA has significant discretion in weighing the different criteria, and may weigh them differently in different rulemakings.

For the present proposal, the EPA is heavily weighting three criteria in particular: The amount of emission reductions, the cost of achieving those reductions, and the promotion of technology implementation—while also noting that the proposed BSER determination readily meets the other criteria as well. The EPA considers it especially important in this rulemaking, while ensuring that electricity system reliability is preserved and that costs are not unreasonable, to achieve a significant amount of emissions reductions in response to the urgency and the magnitude of the need to mitigate climate change. The EPA discusses this above in the sections concerning the scientific background for this rulemaking. The EPA also considers it especially important for the present proposal that the overall costs of achieving the emission reductions should be reasonable. Costs can be minimized through the flexibility to choose from a broad range of CO_2 emission reduction measures, as is provided in the portion of this proposal addressing state plans, and a similarly broad range of emission reduction measures, represented by the four building blocks discussed above, should serve as the basis supporting the BSER. Finally, the EPA also considers it especially important for the present proposal to promote technological innovation and development of, in particular, the measures in building blocks 3 and 4 (to reiterate, low- or zero-carbon electricity generation and demand-side energy efficiency, respectively). Promoting innovation in, and market penetration of, these technologies and practices is critical to making the substantial reductions in emissions that will be required during the next few decades to reduce the risks to public health and welfare and our economic well-being of dangerous climate change.

In addition, in this rulemaking, the EPA is determining the BSER in a manner that is consistent with, and that provides further impetus for, current trends in the nation's electricity system that offer promise to reduce the carbon intensity of the system over the near- and long-term, while maintaining reliability and affordability. This approach is consistent with the case law, which authorizes the EPA to determine BSER by ''balanc[ing] long-term national and regional impacts,'' and by ''using a long-term lens with a broad focus on future costs, environmental and energy effects of different technological systems. . . .''[246]

9. State-Wide Application of the BSER; Appropriateness of Standards of Performance

An important aspect of the BSER for affected EGUs is that the EPA is proposing to apply it on a statewide basis. The statewide approach also underlies the required emission performance level, which is based on the application of the BSER to a state's affected EGUs, and which the suite of measures in the state plan, including the emission standards for the affected

[244] It should be noted that in light of the low current and projected near term prices for natural gas, market forces may lead investors to choose to build new NGCC units, rather than new renewable resources. This result would not call into question the technical feasibility of a BSER that included reductions in fossil fuel-fired generation by the amount of a specified amount of new renewable resources. This is because under these circumstances, the fossil fuel-fired generators could still reduce their generation without causing reliability or other problems in the electric power system.

[245] The nuclear generating capacity reflected in building block 3 is already in operation or under construction.

[246] *Sierra Club* v. *Costle,* 657 F.2d 298, 331 (D.C. Cir. 1981).

EGUs, must achieve overall. The state has flexibility in assigning the emission performance obligations to its affected EGUs, in the form of standards of performance—and, for the portfolio approach, in imposing requirements on other entities—as long as, again, the required emission performance level is met.

This state-wide approach both harnesses the efficiencies of emission reduction opportunities in the interconnected electricity system and is fully consistent with the principles of federalism that underlie the Clean Air Act generally and CAA section 111(d) particularly. That is, this provision achieves the emission performance requirements through the vehicle of a state plan, and provides each state significant flexibility to take local circumstances and state policy goals into account in determining how to reduce emissions from its affected sources, as long as the plan meets minimum federal requirements.

In this subsection, we describe how this approach, and the standards of performance for the affected EGUs that the states will establish through the process we describe, are consistent with the CAA section 111(d)(1) and (a)(1) provisions.

For convenience, we set out the requirements of CAA section 111(d)(1) and (a)(1) here: Under CAA section 111(d)(1), the state must adopt a plan that ''establishes standards of performance for any existing source.'' Under CAA section 111(a)(1), a ''standard of performance'' is a ''standard for emissions . . . which reflects the degree of emission limitation achievable through the application of the best system of emission reduction . . . adequately demonstrated.'' The EPA proposes to interpret these provisions as set forth in this sub-section.

The first step is for the EPA to determine the ''best system of emission reduction . . . adequately demonstrated.'' As discussed at length elsewhere, the EPA is proposing two alternative BSER. The first is the measures in building blocks 1 through 4 combined. This includes operational improvements and equipment upgrades that the coal-fired steam EGUs in the state may undertake to improve their heat rate by, on average, six percent and increases in, or retention of, zero- or low-emitting generation, as well as measures to reduce demand for generation, all of which, taken together, displace, or avoid the need for, generation from the affected EGUs. This BSER is a set of measures that impacts affected EGUs as a group. The alternative approach to BSER is building block 1 combined with reduced utilization from the affected EGUs in the state as a group, in the amounts that can be replaced by an increase in, or retention of, zero- or low-emitting generation, as well as reduced demand for generation.

After determining the BSER, the EPA then applies the BSER to each state's affected EGUs, on a state-wide basis. Building block 1 is applied to the coal-fired steam EGUs on a statewide basis; building block 2 is applied to increase the generation of the NGCC units in the state up to certain amounts, and decrease the amount of generation from steam EGUs accordingly; and the measures in building blocks 3 and 4 are applied to reduce, or avoid, generation from all affected EGUs on a state-wide basis. Under the alternative formulation of the BSER, the total amount of reduced generation from the affected EGUs in the state, associated with the measures in building blocks 2, 3, and 4, is determined on the basis of each state's affected EGUs as a group.

This statewide approach to applying the BSER is consistent with the CAA section 111(a)(1) definition of ''standard of performance,'' which, as quoted above, refers to ''the application of the [BSER],'' for the purpose of determining ''the degree of emission limitation achievable,'' but does not otherwise constrain how the BSER is to be applied.

As a result, the EPA may apply the BSER to all of the affected EGUs in the state as a group. Similarly, the implementing regulations give the EPA broad discretion to identify the group of sources to which the BSER is applied. The regulations provide that the EPA ''will specify different emission guidelines or compliance times or both for different sizes, types, and classes of designated facilities when costs of control, physical limitations, geographical location, or similar factors make subcategorization appropriate.'' Applying the BSER to the affected EGUs in each state as a group is appropriate, and therefore is consistent with these regulations.

As part of applying the BSER, the EPA, to return to provisions of CAA section 111(a)(1), calculates the ''emission limitation achievable through the application of the [BSER].'' In this rulemaking, we refer to this amount as the state goal. As noted, the EPA expresses the state goal in the emission guidelines as an emission rate.

The state must develop a state plan that achieves the state goal, either in the form of an emission rate, as specified for the state in the emission guidelines, or a translated mass-based version of the rate-based goal. We refer to the state goal, in the form used by the state as the foundation of its plan, as the required emission performance level.

As part of its state plan, the state must establish ''standards of performance'' for its affected EGUs. To do so, the state may consider the measures the EPA identified as part of the BSER or other measures that reduce emissions from the affected EGUs. Moreover, the state has the flexibility to establish emission standards in the degree of stringency that the state considers appropriate. The primary limitation on the state's flexibility is that the emission standards applied to all of the state's affected EGUs—and, in the case of states that adopt the portfolio approach, the requirements imposed on other affected entities—taken as a whole, must be demonstrated to achieve the required emission performance level. In addition, the state may make the emission standards for any of its affected EGUs sufficiently stringent, so that the standards and any requirements imposed on other affected entities (if relevant), taken as a whole, achieve a level of emission performance that is better than the required emission performance level. *See* CAA section 116, 40 CFR 60.24(g).

Under these circumstances—that the emission standards that the state establishes for its affected EGUs and any other requirements for the other affected entities, as relevant, taken together, are at least as stringent as necessary to achieve the required emission performance level for the state's affected EGUs—each emission standard that the state adopts for each of its affected EGUs will meet the definition of a ''standard of performance'' under CAA section 111(a)(1). Specifically, the ''standard of performance'' for each source will constitute, to return to the provisions of CAA section 111(a)(1), ''a standard for emissions which reflects [that is, embodies, or represents] [247] the degree [that is, the portion] of emission limitation achievable through the application of the [BSER]'' [that is, as noted above, the required emission performance level for all affected sources in a state]. That ''degree'' or portion of the required emission performance level is, in effect, the portion of the state's obligation to limit its affected sources' emissions that the state has assigned to each particular affected source. An emission standard

[247] *See* Oxford Dictionary of English (3rd ed. 2010 (online version 2013)) (defining ''reflect'' as, among other things, ''embody or represent (something) in a faithful or appropriate way'').

meets this definition of the term ''standard of performance'' regardless of whether it is part of a plan that adopts the portfolio approach (in which case, the standard will reflect a relatively smaller part of the emission performance level) or one that imposes the plan's emission limitation obligations entirely on the affected EGUs (in which case, the standard will reflect a relatively larger part of the emission performance level).

These proposed interpretations of the provisions of CAA sections 111(d)(1) and (a)(1) are fully consistent with the EPA's overall approach in this rulemaking to determining and applying the BSER and identifying the appropriate level of emission performance for the affected EGUs. As noted, this approach entails applying the BSER on a state-wide basis and, based on the BSER, identifying the emission performance level for each state's affected EGUs that each state must achieve, so that each state may then assign the emission limitation obligations among its sources. As noted, this approach is fully consistent with the interconnected nature of the electricity system and with the principles of federalism that underlie CAA section 111(d).

It should be emphasized that each state has many options for assigning the emission limitation obligations among its affected sources. For example, the state could impose emission standards that are consistent with the BSER. Under these circumstances, the state may assign to different affected sources emission standards with different levels of stringency because the state will have determined that those standards are consistent with the nature of each source's participation in the state's electricity system. In addition, the state could authorize emission trading as part of the emission standards for affected sources. Under these circumstances, if an affected source's emission level was higher than the standard the state established for it, the source could achieve the standard by purchasing additional emission rights through the trading program.

Finally, it should be noted that states retain authority under CAA section 116 and 40 CFR 60.24(g) to impose standards of performance that, cumulatively, are more stringent than the emission performance level.[248]

10. Combined Categories

As discussed above, the EPA is soliciting comment on combining the category of steam EGUs and the category of combustion turbines (which include NGCC units) into a single category for fossil fuel-fired EGUs, for purposes of promulgating emission guidelines for CO_2 emissions. The EPA solicits comment on whether combining the categories is, as a legal matter, a prerequisite for (i) identifying as a component of the BSER re-dispatch between sources in the two categories (i.e., re-dispatch between steam EGUs and NGCC units), or (ii) facilitating averaging or trading systems that include sources in both categories, which states may wish to adopt.

11. Severability

We consider our proposed findings of the BSER with respect to the various building blocks to be severable, such that in the event a court were to invalidate our finding with respect to any particular building block, we would find that the BSER consists of the remaining building blocks. The state goals that would result from any combination of the building blocks can be computed from data included in the Goal Computation TSD and its appendices using the methodology described in the preamble and that TSD.

12. Solicitation of Comment

We invite comment on all aspects of our proposed interpretation and alternate interpretation of the BSER for CO_2 emissions from existing fossil fuel-fired EGUs, both as identified above and as further discussed in the Legal Memorandum in the docket.[249] In particular, we invite comment on our analysis of the four building blocks as components of the BSER, whether any other potential measures should be considered, our analysis of the combinations of building blocks 1 and 2 and of all four building blocks, and the legal, technical, and economic bases of our conclusions. With regard to comments received during the stakeholder meetings, some commenters noted that trading programs like RGGI have been successful at reducing GHGs, and other commenters provided specific BSER proposals based on trading and/or emissions averaging approaches. We specifically request comment on whether any of these approaches should be considered as the BSER. We also specifically invite comment on the question, raised by some stakeholders, as to whether if measures may be relied on in the state plan to achieve emissions reductions, they cannot be excluded from the scope of the BSER solely because they involve actions by entities or at locations other than affected sources.

VII. State Goals

A. Overview

In this section, the EPA sets out proposed state-specific CO_2 emission performance goals to guide states in development of their state plans. The proposed goals reflect the EPA's quantification of each state's average emission rate from affected EGUs that could be achieved by 2030 and sustained thereafter, with interim goals that would apply over a 2020–2029 phase-in period, through reasonable implementation, considering the unique circumstances of each individual state, of the best system of emission reduction adequately demonstrated (based on all four building blocks) described above. In addition, we are taking comment on a second set of state-specific goals that would reflect less stringent application of the same BSER, in this case by 2025, with interim goals that would apply over a 2020–2024 phase-in period. As promulgated in the final rule following consideration of comments received, the interim and final goals will be binding emission guidelines for state plans.

The proposed goals are expressed in the form of state-specific, adjusted[250] output-weighted-average CO_2 emission rates for affected EGUs. However, states are authorized to translate the form of the goal to a mass-based form, as long as the translated goal achieves the same degree of emission limitation.[251]

The EPA is also proposing that measures taken by a state or its sources

[248] The EPA's approach may also be characterized as (i) determining the BSER for the affected EGUs, (ii) establishing as the emission guideline the standard for emissions that the affected EGUs in the state can achieve on average through the application of the BSER, and (iii) as part of the emission guideline, authorizing each state to establish as the applicable standard for each affected EGU, the standard that the state considers appropriate and that when totaled with the standards established for the other EGUs (and as may be adjusted to account for the portfolio approach, if that approach is adopted by the state) is at least as stringent as the average standard in the emission guideline. As noted in the accompanying text, a state has many ways to establish standards that meet the CAA requirements, including, for example, following the BSER or authorizing emission rate averaging or trading.

[249] However, as noted, we are not soliciting comment on issues that were resolved by the implementing regulations.

[250] As described below, the emission rate goals include adjustments to incorporate the potential effects of emission reduction measures that address power sector CO_2 emissions primarily by reducing the amount of electricity produced at a state's affected EGUs (associated with, for example, increasing the amount of new low- or zero-carbon generating capacity or increasing demand-side energy efficiency) rather than by reducing their CO_2 emission rates per unit of energy output produced.

[251] A method for translating from a rate-based goal to a mass-based goal is discussed in the Projecting CO_2 Emission Performance in State Plans TSD.

after the date of this proposal, or programs already in place, and which result in CO_2 emission reductions at affected EGUs during the 2020–2030 period, would apply toward achievement of the state's CO_2 goal. Thus, states with currently existing programs and policies, and states that put in place new programs and policies early, will be better positioned to achieve the goals.

The EPA is proposing to finalize the goal for each state as proposed, and adjusted as may be appropriate based on comments. A state may demonstrate during the comment period that application of one of the building blocks to that state would not be expected to produce the level of emission reduction quantified by the EPA because implementation of the building block at the levels envisioned by the EPA was technically infeasible, or because the costs of doing so were significantly higher than projected by the EPA. While the EPA would consider this in setting final state goals, the EPA would also consider (and would expect commenters to address) whether a similar overall state goal could still be achieved through more aggressive implementation of one or more of the measures encompassed in the other building blocks or through other, comparable measures. For example, if a state demonstrates during the public comment period that the state's coal-fired steam EGUs could only achieve an average four percent heat rate improvement, instead of the six percent that the EPA is proposing to determine is achievable from application of building block 1, the EPA would not adjust the state's goal to reflect that change unless the state also demonstrates that it could not get additional reductions from application of building blocks 2, 3 or 4, or in related, comparable measures.

Each of the building blocks establishes a reasonable level of reductions, but not necessarily the maximum amount that could be achieved if that building block, and no other, were the basis supporting the BSER. Together the building blocks establish a reasonable overall level of reductions and effort that the EPA considers appropriate at this time. This amount of emission reductions is significant and will require effort and adjustments throughout the electricity sector. In light of the overall effort to achieve the state goals based on a combination of all four building blocks at the levels specified, the EPA is not proposing a higher level of reductions at this time, even though the measures in the building blocks could be implemented more stringently to achieve greater emission reductions.

Because the building blocks each establish a reasonable level of emission reduction rather than the maximum possible level of reduction, the EPA expects that, for any particular state, even if the application of the measures in one building block to that state would not produce the level of emission reductions reflected in the EPA's quantification for that state, the state will be able to reasonably implement measures in other of the building blocks more stringently, so that the state would still be able to achieve the proposed goal. Accordingly, the EPA proposes that even if a state demonstrates during the comment period that application of a building block to that state would not result in the level of emission reductions reflected in the EPA's quantification for that state, then the state should also explain why the application of the other building blocks would not result in greater emission reductions than are reflected in the EPA's quantification for that state. In light of the fact that the building blocks are based on a reasonable level of stringency and not the most stringent possible level, the EPA expects that such offsetting emission reductions at the state's affected EGUs from the application of other building blocks will be available, so that the EPA will be able to finalize the state goals as proposed. For example, a state's inability to meet the level of emission reductions anticipated through use of one building block may free up resources that the state could then devote to more stringent implementation of another building block. This approach would mean that overall, the same nationwide level of emission reductions as proposed would be achieved. The EPA invites comment on this aspect of the proposal.

At this time, the EPA is not proposing CO_2 emission performance goals for either Indian country or U.S. territories. The EPA does plan to establish CO_2 emission goals for both Indian country and territories in the future. The EPA plans to conduct additional outreach before setting these goals.

Issues related to the establishment of CO_2 goals and CAA section 111(d) plans for Indian country are discussed in Section V.D of this preamble. As noted in that discussion, the EPA is aware of four potentially affected power plants located in Indian country: The South Point Energy Center, on Fort Mojave tribal lands within Arizona; the Navajo Generating Station, on Navajo tribal lands within Arizona; the Four Corners Power Plant, on Navajo tribal lands within New Mexico; and the Bonanza Power Plant, on Ute tribal lands within Utah.[252] Data for these four power plants have been excluded from the data used to compute the proposed state goals for Arizona, New Mexico, and Utah discussed below.

With respect to territories, the EPA is currently aware of potentially affected EGUs in Puerto Rico, the U.S. Virgin Islands, and Guam. The EPA requests comment on how the BSER would apply to these territories, as well as to American Samoa or the Northern Mariana Islands if potentially affected EGUs are subsequently identified in those territories. In particular, the EPA solicits comment on appropriate alternatives for territories that do not have access to natural gas.[253] Because the data sources we have used for purposes of establishing renewable energy and demand-side energy efficiency targets for states do not cover all the territories, we also solicit comment on ways to determine appropriate renewable energy and demand-side energy efficiency targets using other data sources.

The remainder of this section addresses five sets of topics. First, we discuss several issues related to the form of the goals. Second, we describe the proposed state goals and the computation procedure. Third, we discuss several types of state flexibility with respect to the goals. Fourth, we describe the alternate set of goals offered for comment and certain other approaches we considered. Finally, we discuss the proposal's compatibility with the need to ensure a reliable, affordable supply of electricity.

Some of the topics addressed in this section are addressed in greater detail in supplemental documents available in the docket for this rulemaking, including the Goal Computation TSD and the Greenhouse Gas Abatement Measures TSD. Specific topics addressed in the various TSDs are noted throughout the discussion below.

B. Form of Goals

The proposed goals are presented in the form of adjusted output-weighted-average CO_2 emission rates that the affected fossil fuel-fired EGUs located in each state could achieve, on average, through application of the measures

[252] The South Point facility is an NGCC power plant, and the Navajo, Four Corners, and Bonanza facilities are coal-fired power plants.

[253] As noted in Section VI.C.5.d above, we are requesting comment on whether heat rate improvements for non-coal fossil fuel-fired EGUs should be part of the basis supporting the BSER, with particular reference to the situation of geographically isolated jurisdictions such as the U.S. territories.

comprising the BSER (or alternative control methods). Several aspects of this proposed form of goal are worth noting at the outset: The use of an emission rate-based form (e.g., the quantity of CO_2 per MWh of electricity generated), with the opportunity for the state to adopt a mass-based form (e.g., a cap on the tonnage of CO_2 emissions); the use of output-weighted-average emission rates for all affected EGUs in a state rather than nationally uniform emission rates for all affected EGUs of particular types; the use of adjustments to accommodate measures that reduce CO_2 emissions by reducing the quantity of fossil fuel-fired generation rather than by reducing the CO_2 emission rate per MWh generated by affected sources; the use of emission rates expressed in terms of net rather than gross energy output; and the adjustability of the goals based on the severability of the underlying building blocks.

First, the EPA proposes to use an emission rate-based form for the state-specific goals included in the guidelines, and to give each state the opportunity to translate its rate-based goal to an equivalent mass-based form for state plan purposes. Each of the two forms of goals presents advantages, and states have expressed support for having the flexibility to use either form. Defining emission performance levels in a rate-based form provides flexibility to accommodate changes in the overall quantities of electricity generated in response to increases in electricity demand. Defining emission performance levels in a mass-based form provides relative certainty as to the absolute emission levels that would be achieved as well as relative simplicity in accommodating and accounting for the emission impacts of a wide variety of emission reduction strategies. In light of these respective advantages, we propose to set an emission rate-based form of goal, and to allow any state to translate the rate-based goal to an equivalent mass-based emission performance level for state plan purposes. This approach allows each state to maximize the advantages it considers optimal and is consistent with the state flexibility principle that is central to the EPA's development of this program.

The second aspect noted above concerns the proposed choice of state-specific output-weighted-average emission rates for all affected EGUs in each state rather than nationally uniform emission rates for particular types of affected EGUs. Here, the EPA's main consideration has been to ensure that the proposed goals reflect opportunities to manage CO_2 emissions by shifting generation among different types of affected EGUs. Specifically, because CO_2 emission rates differ widely across the fleet of affected EGUs, and because transmission interconnections typically provide system operators with choices as to which EGU should be called upon to produce the next MWh of generation needed to meet demand, opportunities exist to manage utilization of high carbon-intensity EGUs based on the availability of less carbon-intensive generating capacity. For states and generators, this means that CO_2 emission reductions can be achieved by shifting generation from EGUs with higher CO_2 emission rates, such as coal-fired EGUs, to EGUs with lower CO_2 emission rates, such as NGCC units. Our analysis indicates that shifting generation among EGUs offers opportunities to achieve large amounts of CO_2 emission reductions at reasonable costs. These opportunities can be reflected in a goal established in the form of an output-weighted-average emission rate for multiple affected EGU types. Our approach is also consistent with the fact that the proportions of different EGU types and hence the magnitudes of the generation-shifting opportunities vary across states, and that CAA section 111(d) calls for standards of performance to be established in state plans rather than on a nationwide basis.

The third aspect noted above regarding the proposed form of the goals concerns the adjustments made to the output-weighted-average emission rates in order to accommodate reduced utilization of affected EGUs associated with measures such as increases in low- and zero-carbon generating capacity and demand-side energy efficiency. We recognize that these measures support reduced overall CO_2 mass emissions from affected EGUs through reductions in the quantity of generation from affected EGUs, and not necessarily through reductions in the weighted-average CO_2 emission rates of affected EGUs. Accordingly, we have constructed the emission rate goals in a manner that is intended to account for these generation quantity-reducing measures by making adjustments to the values used in the emission rate computations. The specific adjustments are summarized below in the context of the goal computation methodology and are described in greater detail in the Goal Computation TSD. As described below in Section VIII on state plans, we are proposing that a state choosing a rate-based form of goal would be able to make analogous adjustments when assessing monitored emission performance so that measures that support avoided generation at affected EGUs could be used to help the state meet the rate-based emission performance level reflected in its plan. We note that adjustments of this nature are not necessary when a plan's emission performance level is based on the mass of CO_2 emissions [254] rather than on CO_2 emission rates, because the emission-reducing effects of reduced generation at affected EGUs are evident in the EGUs' reported CO_2 mass emissions.

The fourth aspect noted above concerns the proposed expression of the goals in terms of net energy output [255]—that is, energy output encompassing net MWh of generation measured at the point of delivery to the transmission grid rather than gross MWh of generation measured at the EGU's generator.[256] The difference between net and gross generation is the electricity used at a plant to operate auxiliary equipment such as fans, pumps, motors, and pollution control devices. Because improvements in the efficiency of these devices represent opportunities to reduce carbon intensity at existing affected EGUs that would not be captured in measurements of emissions per gross MWh, we are proposing goals expressed in terms of net generation. Nearly all EGUs already have in place the equipment necessary to determine and report hourly net generation, and we believe that the proposed reporting requirement would therefore not be burdensome. However, we also recognize that at present EGUs report gross rather than net load [257] to us under 40 CFR Part 75, and that the proposed GHG standards of performance for new EGUs are expressed in terms of gross generation (although we sought comment on the use of net generation instead). We therefore specifically seek comment on whether the goals and reporting requirements for existing EGUs should be expressed in terms of

[254] We also recognize that even under a mass-based approach, adjustments may be appropriate in some circumstances to address interstate effects, such as when measures undertaken pursuant to one state's plan are expected to be associated with decreases in fossil fuel-fired generation and CO_2 emissions in another state. These issues are discussed below in Section VIII on state plans.

[255] As discussed below in Section VIII on state plans, we are similarly proposing that states choosing a rate-based form of emission performance level for their plans should establish a requirement for affected EGUs to report hourly net energy output.

[256] For some EGUs, total net or gross energy output also includes useful thermal output, in addition to either net or gross electric energy output.

[257] Some EGUs report gross steam output instead of gross electrical load.

gross generation instead of net generation for consistency with existing reporting requirements and with the proposed requirements under the GHG standards of performance for new EGUs.

The final aspect noted above has to do with the severability of the four building blocks, discussed in Section VI above, upon which the goals are based. Because the building blocks can be implemented independently of one another and the goals are the sum of the emission reductions from all of the building blocks, if any of the building blocks is found to be an invalid basis for the ''best system of emission reduction . . . adequately demonstrated,'' the goals would be adjusted to reflect the emissions reductions from the remaining building blocks. As noted above, the state goals that would result from any combination of the building blocks can be computed from data included in the Goal Computation TSD and its appendices using the methodology described below and in that TSD.

We invite comment on all aspects of the proposed form of the goals.

C. Proposed Goals and Computation Procedure

The EPA has developed proposed goals for state plans reflecting application of the BSER, based on all four building blocks described earlier, to pertinent data for each state. The goals are intended to represent CO_2 emission rates achievable by 2030 after a 2020–2029 phase-in period on an output-weighted-average basis collectively by all of a state's affected EGUs, with certain computation adjustments described below to reflect the potential to achieve mass emission reductions by avoiding fossil fuel-fired generation. For each state, in addition to the final goal, the EPA has developed an interim goal that would apply during the 2020–2029 period on a cumulative or average basis as the state progresses toward the final goal. The proposed goals are set forth in Table 8 below, followed by a description of the computation methodology. (The issue of how states could demonstrate emission performance consistent with the interim and final goals is addressed in Section VIII on state plans.)

TABLE 8—PROPOSED STATE [258] GOALS

[Adjusted output-weighted-average pounds of CO_2 per net MWh from all affected fossil fuel-fired EGUs]

State	Interim goal	Final goal
Alabama	1,147	1,059
Alaska	1,097	1,003
Arizona *	735	702
Arkansas	968	910
California	556	537
Colorado	1,159	1,108
Connecticut	597	540
Delaware	913	841
Florida	794	740
Georgia	891	834
Hawaii	1,378	1,306
Idaho	244	228
Illinois	1,366	1,271
Indiana	1,607	1,531
Iowa	1,341	1,301
Kansas	1,578	1,499
Kentucky	1,844	1,763
Louisiana	948	883
Maine	393	378
Maryland	1,347	1,187
Massachusetts	655	576
Michigan	1,227	1,161
Minnesota	911	873
Mississippi	732	692
Missouri	1,621	1,544
Montana	1,882	1,771
Nebraska	1,596	1,479
Nevada	697	647
New Hampshire	546	486
New Jersey	647	531
New Mexico *	1,107	1,048
New York	635	549
North Carolina	1,077	992
North Dakota	1,817	1,783
Ohio	1,452	1,338
Oklahoma	931	895
Oregon	407	372
Pennsylvania	1,179	1,052
Rhode Island	822	782
South Carolina	840	772
South Dakota	800	741
Tennessee	1,254	1,163
Texas	853	791
Utah *	1,378	1,322
Virginia	884	810
Washington	264	215
West Virginia	1,748	1,620
Wisconsin	1,281	1,203
Wyoming	1,808	1,714

* Excludes EGUs located in Indian country within the state.

The proposed goals are expressed as adjusted output-weighted-average emission rates for all affected EGUs in a state. As discussed earlier in this section, a goal expressed as an unadjusted output-weighted-average emission rate would fail to account for mass emission reductions from reductions in the total quantity of fossil fuel-fired generation associated with state plan measures that increase low- or zero-carbon generating capacity or demand-side energy efficiency. Accordingly, under the proposed goals, the emission rate computation includes an adjustment designed to reflect those mass emission reductions. The adjustment is made by estimating the annual net generation associated with an achievable amount of qualifying new low-carbon and zero-carbon generating capacity, as well as the annual avoided generation associated with an achievable portfolio of demand-side energy efficiency measures, and adding those MWh amounts to the energy output from affected units that would have been used in an unadjusted output-weighted-average emission rate computation.[259] Mathematically, this adjustment has the effect of spreading the measured CO_2 emissions from the state's affected EGUs over a larger quantity of energy output, thus resulting in an adjusted emission rate lower than the unadjusted emission rate. (As discussed below in Section VIII on state plans, we are proposing that a state could make analogous adjustments to compliance measurement approaches under its state plan, thereby enabling the state to adopt an emission rate-based form of emission performance level while still being able to rely on low- or zero-carbon capacity deployment programs and demand-side energy efficiency as components of its plan.)

The methodology used to compute each state's proposed goal is summarized on a step-by-step basis below. The methodology is described in more detail in the Goal Computation TSD, which includes a numerical example illustrating the full procedure. The development of the data inputs used in the computation procedure is discussed in Section VI above and in the Greenhouse Gas Abatement Measures TSD.

Step 1 (compilation of baseline data). On a state-by-state basis, we obtained total annual quantities of CO_2 emissions, net generation (MWh), and capacity (MW) from reported 2012 data for all affected EGUs.[260] For each state,

[258] The EPA has not developed goals for Vermont and the District of Columbia because current information indicates those jurisdictions have no affected EGUs. Also, as noted above, the EPA is not proposing goals for Indian country or U.S. territories at this time.

[259] In the case of new capacity that is not zero-carbon, an adjustment would also be required to the emissions value used in computing the weighted-average emission rate. This procedure is discussed further in the Goal Computation TSD.

[260] EGUs whose capacity, fossil fuel combustion, or electricity sales were insufficient to qualify them as affected EGUs were not included in the goal computations. Most simple cycle combustion

Continued

we aggregated the 2012 data for all coal-fired steam EGUs as one group, all oil- and gas-fired steam EGUs as a second group, and all NGCC units as a third group. We aggregated the 2012 data for all remaining affected EGUs (i.e., integrated gasification combined-cycle (IGCC) units and any simple-cycle combustion turbines satisfying relevant thresholds for qualification as affected EGUs) as a fourth, ''other'' group.[261] To these totals for affected EGUs operating in 2012, we added estimates for other EGUs not yet in operation in 2012 that are affected EGUs for purposes of this emission guideline.[262] Capacity and emission rate data inputs for the post-2012 affected EGUs were obtained from the NEEDS database maintained by the EPA for use with the Integrated Planning Model (IPM). Generation data inputs for the post-2012 affected EGUs were estimated based on the average 2012 utilization rates for recently constructed EGUs of the same types; for example, we estimated in this step that the post-2012 NGCC units would operate at a 55 percent utilization rate on average.

Step 2 (application of building block 1). The total CO_2 emissions amount for the coal-fired steam EGU group in each state from Step 1 was reduced by six percent, reflecting our assessment of the average opportunity to reduce CO_2 emission rates across the existing fleet of coal-fired steam EGUs through heat rate improvements that is technically achievable at a reasonable cost.

Step 3 (application of building block 2). If the generation data for the NGCC group in a state developed in Step 1 showed average annual utilization below 70 percent of those units' maximum possible output, and the generation data developed in Step 1 also included generation from the coal-fired steam or oil/gas-fired steam EGU groups in that state, the generation and emissions figures for the NGCC group were increased, and the generation and emissions figures for the coal-fired and oil/gas-fired steam EGU groups from Step 2 were proportionately[263] decreased, to reflect an estimated potential increase in utilization of the NGCC group to a maximum of 70 percent. In this step, the total (across all four groups) of the state's fossil fuel-fired generation was maintained at the amount computed in Step 1, but to the extent that in the analysis a portion of the total fossil generation was shifted from the coal-fired and oil/gas-fired steam EGU groups, which have higher CO_2 emission rates, to the NGCC group, which has a lower CO_2 emission rate, the total (across all four groups) of the state's CO_2 emissions was reduced.[264]

Step 4 (application of building block 3). We estimated the total quantities of generation from renewable generating capacity and from under-construction or preserved nuclear capacity for each state using the approaches described in Section VI.C.3 above. Separate estimates of renewable generation were computed for each year of the plan period for each state based on the state's 2012 renewable generation and a regional growth factor. Nuclear generation was estimated as the amount of under-construction and preserved nuclear capacity for each state operated at a utilization rate of 90 percent, consistent with recent industry-wide average utilization rates for nuclear units.

Step 5 (application of building block 4). We estimated the total MWh amount by which generation from each state's affected EGUs would be cumulatively reduced in each year of the plan period associated with implementation in that state of demand-side energy efficiency programs resulting in annual incremental reductions in the state's electricity usage (relative to usage absent those programs) of 1.5 percent each year, as described in Section VI.C.4 above. Separate estimates were developed for each year to reflect the fact that energy efficiency programs that are implemented on an ongoing basis would be expected to produce larger cumulative impacts on total annual electricity usage over time. For states that are net importers of electricity, the estimated reduction in the generation by the state's affected EGUs was scaled down to reflect an expectation that a portion of the generation avoided by the demand-side energy efficiency would occur at EGUs in other states.

Step 6 (computation of annual rates). We computed adjusted output-weighted-average CO_2 emission rates for each state by dividing (1) the total CO_2 emissions for the coal-fired steam EGU, oil- and gas-fired steam EGU, NGCC unit, and ''other'' affected fossil EGU groups from Step 3 above by (2) the total of (a) the total net energy output (expressed in MWh) for the four groups from Step 1 above plus (b) the estimated annual net generation from renewable and nuclear generating capacity from Step 4 above plus (c) the estimated cumulative annual MWh amount saved through demand-side energy efficiency from Step 5 above.[265] We performed these computations separately for each year from 2020 to 2029, using the respective cumulative annual MWh savings figures developed in Steps 4 and 5.

Step 7 (computation of interim and final goals). The final 2030 goal for each state is the annual rate computed for 2029 for the state from Step 6 above. We computed the 2020–2029 interim goal for each state as the simple average of the annual rates computed for each of the years from 2020 to 2029 for the state from Step 6 above.

It bears emphasis that the procedure described above is proposed to be used only to determine state goals, and the particular data inputs used in the procedure are not intended to represent specific requirements that would apply to any individual EGU or to the collection of EGUs in any state. The specific requirements applicable to individual EGUs, to the EGUs in a given state collectively, or to other affected entities in the state, would be based on the standards of performance established through that state's plan. The details of how states could attain emission performance levels consistent with the goals through different state plan approaches that recognize emission reductions achieved through all the building blocks are discussed further in Section VIII on state plans.

We invite comment on all aspects of the goal computation procedure. (Note that we also invite comment on certain specific alternate data inputs to the procedure in Section VI.C above.) We also specifically invite comment on the state-specific historical data to which

turbines were excluded on this basis. See the applicability criteria described in Section V.B. above.

[261] The emission and generation totals for the ''other'' group also reflect the portion of affected cogeneration units' total CO_2 emissions and total energy output corresponding to those units' useful thermal output.

[262] Assuming it meets other applicability criteria, an EGU would be affected if it had commenced construction by January 8, 2014 (the data of **Federal Register** publication of the proposed GHG NSPS for new EGUs).

[263] For example, if the data developed in Step 1 showed equal quantities of MWh generated by the coal-fired steam EGU group and the oil/gas-fired steam EGU group, then any overall reduction in the MWh generated by these two groups due to a commensurate increase in the MWh generated by the less carbon-intensive NGCC group would be split equally between the coal-fired steam group and the oil/gas-fired steam group.

[264] We did not estimate any change in utilization, generation, or emissions for the state's ''other'' group of IGCC units and simple-cycle combustion turbines in Step 3.

[265] Expressed as a formula, the equation for the annual rate computation is:

[(Coal gen. × Coal emission rate) + (OG gen. × OG emission rate) + (NGCC gen. × NGCC emission rate) + ''Other'' emissions]/[Coal gen. + OG gen. + NGCC gen. + ''Other'' gen. + Nuclear gen. + RE gen. + EE gen.]

This formula and its elements are further explained in the Goal Computation TSD, as well as in the text above.

the building blocks are applied in order to compute the state goals, as well as the state-specific data used to develop the state-specific data inputs for building blocks 3 and 4. These data are contained in the Goal Computation TSD and the Greenhouse Gas Abatement Measures TSD.

With respect to building block 2, we specifically request comment on the following alternate procedure: In Step 3, to the extent that generation from a state's NGCC group was increased consistent with the NGCC utilization rate target, in order to maximize the resulting emission reductions, we would decrease generation from the state's coal-fired steam group first, and then decrease generation from the state's oil/gas-fired steam group (instead of decreasing generation from the coal-fired steam and oil/gas-fired steam groups proportionately).

With respect to building block 4, we specifically invite comment on the alternative in Step 5 of scaling up the estimated reduction in the generation by affected EGUs in net electricity-exporting states to reflect an expectation that a portion of the generation avoided in conjunction with the demand-side energy efficiency efforts of other, net electricity-importing states would occur at those EGUs, analogous to the proposed adjustment for net electricity-importing states described in Step 5. We also request comment on the alternative of making no adjustment in Step 5 for either net electricity-importing or net electricity-exporting states. These alternatives are discussed in the Goal Computation TSD.

We also request comment on whether CO_2 emission reductions associated with other measures not currently included in any of the four proposed building blocks should be included in the state goals.

D. State Flexibilities

As promulgated in the final rule following consideration of comment, the state-specific goals will be binding emission guidelines. States' ability to achieve emission performance levels consistent with the binding goals is enhanced by several distinct types of flexibility: (i) Choices as to the measures employed, including the timing of their implementation; (ii) the ability to translate from a rate-based form of goal to a mass-based form of goal; and (iii) the opportunity to pursue multi-state plan approaches.

First, a core flexibility provided under CAA section 111(d) is that while states are required to establish standards of performance that reflect the degree of emission limitation from application of the control measures that the EPA identifies as the BSER, they need not mandate the particular control measures the EPA identifies as the basis for its BSER determination. In developing the building block data inputs applied to each state's historical data to develop the goals, the EPA targeted reasonably achievable rather than maximum performance levels. The overall goals therefore represent reasonably achievable emission performance levels that provide states with flexibility to pursue some building blocks more extensively and others less extensively than the degree reflected in the EPA's data inputs while meeting the overall goals. States can also choose to include in their plans other measures that reduce CO_2 emissions at affected EGUs but that are not included in the building blocks.

Further, by allowing states to demonstrate emission performance by affected EGUs on an average basis over a multi-year interim plan period of as long as ten years, the EPA's proposed approach increases states' flexibility to choose among alternative potential plan measures. For example, by taking advantage of the multi-year flexibility, a state could choose to rely more heavily in its plan on measures whose effectiveness tends to grow over time, such as demand-side energy efficiency programs. This flexibility could also help states address concerns about stranded assets, for example, by enabling states to defer imposition of requirements on EGUs that may be scheduled to retire after 2020 but before 2029.

The second type of flexibility noted above is that while the EPA is proposing to establish goals in an emission rate-based form, we are also proposing to provide states with the flexibility to translate the rate-based goals to mass-based goals in order to accommodate states' potential interest in having emission performance requirements measured in absolute tons. For example, the northeastern and Mid-Atlantic states that currently participate in the mass-based Regional Greenhouse Gas Initiative (RGGI) may choose to develop state plans (or a multi-state plan, as noted below) establishing mass-based emission performance levels designed to be met at least in part through standards of performance based on RGGI's existing market-based CO_2 emission budget trading program. Because the use of mass-based plans can simplify the process of accounting for the CO_2 reduction impacts of a variety of measures, the EPA believes the flexibility to adopt mass-based emission performance levels can facilitate plan development and could be attractive to states that do not already participate in mass-based emission reduction programs as well.

Third, the EPA's approach allows states to submit multi-state plans. The EPA expects this flexibility to reduce the cost of achieving the state goals and therefore expects it to be attractive to states. For example, the RGGI-participating states could choose to submit a multi-state mass-based plan that demonstrates emission performance by affected EGUs on a multi-state basis. Additional states may also choose to join a multi-state plan. The mechanics of translating rate-based goals into mass-based goals and considerations related to multi-state plans are discussed below in Section VIII on state plans.

Some stakeholders have suggested that states themselves should be allowed to quantify the level of emission reduction resulting from the application of BSER or, if the EPA establishes goals, the states should be allowed to adjust the goals or to treat the goals established by the EPA as advisory rather than binding. Consistent with the existing implementing regulations for CAA section 111(d) at 40 CFR part 60, this quantification is the EPA's role.[266] As discussed in the Legal Memorandum, CAA section 111(d) directs the EPA to ''prescribe regulations which shall establish a procedure similar to that provided by [CAA section 110] under which each State shall submit'' a section 111(d) state plan. As noted in Section II.D of this preamble, the EPA promulgated implementing regulations in 1975, and has revised parts of them since. The regulations set out a multi-step process for the development and approval of state plans, and assign responsibility for the various steps in the process to the EPA or the states. The regulations provide that the EPA is to promulgate an ''emission guideline that reflects the application of the best system of emission reduction (considering the cost of such reduction) that has been adequately demonstrated for'' affected sources.[267] In this manner, the regulations make clear that the EPA determines the BSER. In this rulemaking, as discussed above, the EPA identifies the BSER. In addition, in this rulemaking, the EPA applies the BSER to each state, and then, for each state, calculates the average emission rate that, in the words of the regulations just quoted, ''reflects the application of

[266] 40 CFR 60.22(b)(5). We do not propose to re-open that portion of the implementing regulations in this rulemaking.

[267] *Id.*

the [BSER].'' That average emission rate is the state goal.

By the same token, because the state goals are an integral part of the emission guidelines that the framework regulations authorize the EPA to establish, the goals are binding, and the states, in their CAA section 111(d) plans, must meet those goals and may not make them less stringent. This matter, too, is resolved by the implementing regulations.[268] To reiterate, the proposed state goals represent the level of performance that is achievable through application of the BSER to the pertinent data for each individual state. States have the opportunity to comment on the proposed BSER, the proposed methodology for computing state goals based on application of the BSER, and the state-specific data that is proposed for use in the computations. We expect that the states will have an adequate opportunity to comment on the state goals during the comment period. Once the final goals have been promulgated, and adjusted as may be appropriate based on comments to address any factual errors in the analysis, the states will be able to meet them because they will represent the application of BSER to the states' affected sources. In addition, states have several types of flexibilities in developing their state plans: They have flexibility regarding the selection of the measures upon which they choose to rely and a 10-year time period over which to reach full implementation of these measures, and they can use rate-based or mass-based approaches. In addition, as we have noted, multi-state coordination offers states an opportunity to achieve additional emission reductions and reduce implementation costs. These flexibilities, discussed further in Section VIII of this preamble, ensure that states will be able to achieve their final CO_2 emission performance goals and that no special provision for state adjustment of goals outside the normal notice-and-comment rulemaking process is warranted.[269]

E. Alternate Goals Offered for Comment and Other Approaches Considered

In addition to the proposed state-specific emission rate-based goals described above, the EPA has developed for public comment an alternate set of goals reflecting less stringent application of the building blocks and a shorter implementation period. The alternate final goals represent emission performance that would be achievable by 2025, after a 2020–2024 phase-in period, with interim goals that would apply during the 2020–2024 period on a cumulative or average basis as states progress toward the final goals.

Because the time period for implementation relates directly to the emission reductions that are achievable and therefore what measures, and at what level of stringency, constitute the BSER, the alternate goals reflect several differences in data inputs from the proposed goals. Specifically, a value of four percent (instead of six percent) was used for the potential improvement in carbon intensity of coal-fired EGUs in Step 2; a value of 65 percent (instead of 70 percent) was used for the potential annual utilization rate of NGCC units in Step 3; and a value of one percent (instead of 1.5 percent) was used for the annual incremental electricity savings achievable through a portfolio of demand-side energy efficiency programs in Step 5. (No change was made to the data inputs regarding less carbon-intensive generating capacity in Step 4.) As noted above, the alternate goals also reflect a shortening of the proposed phase-in period from ten years (2020–2029) to five years (2020–2024) to reflect an expectation that less stringent goals could be achieved in less time. Steps 5, 6, and 7 of the goal computation procedure therefore were performed for the span of years from 2020 to 2024 rather than for the span from 2020 to 2029. The alternate goals are set forth in Table 9 below.

TABLE 9—ALTERNATE STATE[270] GOALS

[Adjusted output-weighted-average pounds of CO_2 per net MWh from all affected fossil fuel-fired EGUs]

State	Interim goal	Final goal
Alabama	1,270	1,237
Alaska	1,170	1,131
Arizona *	779	763
Arkansas	1,083	1,058
California	582	571
Colorado	1,265	1,227
Connecticut	651	627
Delaware	1,007	983
Florida	907	884
Georgia	997	964
Hawaii	1,446	1,417
Idaho	261	254
Illinois	1,501	1,457
Indiana	1,715	1,683
Iowa	1,436	1,417
Kansas	1,678	1,625
Kentucky	1,951	1,918
Louisiana	1,052	1,025
Maine	418	410
Maryland	1,518	1,440
Massachusetts	715	683
Michigan	1,349	1,319
Minnesota	1,018	999
Mississippi	765	743
Missouri	1,726	1,694
Montana	2,007	1,960
Nebraska	1,721	1,671
Nevada	734	713
New Hampshire	598	557
New Jersey	722	676
New Mexico *	1,214	1,176
New York	736	697
North Carolina	1,199	1,156
North Dakota	1,882	1,870
Ohio	1,588	1,545
Oklahoma	1,019	986
Oregon	450	420
Pennsylvania	1,316	1,270
Rhode Island	855	840
South Carolina	930	897
South Dakota	888	861
Tennessee	1,363	1,326
Texas	957	924
Utah *	1,478	1,453
Virginia	1,016	962
Washington	312	284
West Virginia	1,858	1,817
Wisconsin	1,417	1,380
Wyoming	1,907	1,869

* Excludes EGUs located in Indian country in the state.

The EPA recognizes that its approach to the alternate goals, comprising less stringent requirements in each of the building blocks to be achieved over a shorter compliance horizon, follows the logic of including time as one of the functions of the BSER determination. At the same time, we also recognize that the components of the alternate goals may reflect an overly conservative approach. Specifically, the alternate goals as set forth above may underestimate the extent to which the key elements of the four building blocks—achieving heat rate improvements at EGUs, switching generation to NGCC facilities, fostering the penetration of renewable resources or improving year-to-year end-use energy efficiency—can be achieved rapidly while preserving reliability and remaining reasonable in cost. Accordingly, we request comment on the alternate goals, particularly with respect to whether any one or all of the building blocks in the alternate goals

[268] *Id.* We do not propose to re-open that portion of the implementing regulations in this rulemaking.

[269] In the event that a state becomes concerned about its ability to meet the goal that the EPA promulgates for it, the state may submit to the EPA a petition for reconsideration, if that petition is based on relevant information not available during the comment period. *See* CAA section 307(d)(7)(B).

[270] See footnote accompanying Table 8 above.

can be applied at a greater level of stringency: Can the heat rate improvement value be set at a level above four percent, even six percent? Can NGCC capacity be dispatched at a utilization rate above 65 percent? Can annual incremental electricity savings be achieved at a rate higher than one percent?

It is worth noting that the EPA projects that the alternate goals will achieve emission reductions equal to 23 percent below 2005 level in 2025. The EPA's analysis shows that under the proposed goals described in Section VII.C above, power sector emissions will be 29 percent below 2005 levels in 2025, suggesting that the kinds of changes contemplated in the four building blocks, even as early as 2025, will be yielding reductions far greater than the 23 percent projected for the alternate goals as set forth above in this subsection.

The EPA has considered other approaches to setting goals. In particular, given the interconnected nature of the power sector and the importance of opportunities for shifting generation among EGUs, we considered whether goals should be set on a multi-state basis reflecting the scope of existing regional transmission control areas. We also considered whether goals should be set on a state-specific basis, but regional rather than state-specific evaluations should be used to assess the estimated opportunities to reduce utilization of the most carbon-intensive EGUs by shifting generation to less carbon-intensive EGUs. A potential advantage of using regional evaluations is the ability to recognize additional emission reduction opportunities that would be available at reasonable costs based on a more complete representation of the capabilities of existing infrastructure to accommodate shifts in generation among EGUs in multiple states. We request comment on whether, and if so how, the EPA should incorporate greater consideration of multi-state approaches into the goal-setting process, and on the issue of whether, and if so how, the potential cost savings associated with multi-state approaches should be considered in assessing the reasonableness of the costs of state-specific goals.

F. Reliable Affordable Electricity

Many stakeholders raised concerns that this regulation could affect the reliability of the electric power system. The EPA agrees that reliability must be maintained and in designing this proposed rulemaking has paid careful attention to this issue. The EPA has met on several occasions with staff and managers from the Department of Energy and the Federal Energy Regulatory Commission to discuss our approach to the rule and its potential impact on the power system. EPA staff and managers have also had numerous discussions with state public utility commissioners and their staffs to get their suggestions and advice concerning this rule, including how to address reliability concerns.

In addition, the EPA met with independent system operators several times to discuss any potential impact of this rule on grid reliability. The ISO/RTO Council, a national organization of electric grid operators, offered analytic support to help states design programs that do not compromise the regional bulk power system. They also offered to help states develop regional approaches which may reduce costs and strengthen the reliability of the electricity grid. Specifically, the ISO/RTO Council has suggested that ISOs and RTOs could provide analytic support to help states develop and implement their plans. The ISOs and RTOs have the capability to model the system-wide effects of individual state plans. Providing assistance in this way, they felt, would allow states with borders that fall within an ISO or RTO footprint to assess the system-wide impacts of potential state plan approaches. In addition, as the state implements its plan, ISO/RTO analytic support would allow the state to monitor the effects of its plan on the regional electricity system. ISO/RTO analytic capability could help states assure that their plans are consistent with region-wide system reliability. The ISO/RTO Council suggested that the EPA ask states to consult with the applicable ISO/RTO in developing their state plans. The EPA agrees with this suggestion and encourages states with borders that fall within one or more ISO or RTO footprints to consult with the relevant ISOs/RTOs.

The EPA has met with the U.S. Department of Agriculture as well to discuss how we can address the concerns of small, relatively isolated power generators in rural America and especially the electric cooperatives. Many of these entities have special challenges, as they may have small, older carbon-intensive assets and might have particular challenges meeting carbon requirements.

With all of this in mind, the EPA in determining the BSER looked specifically at the reasonableness of the costs of control options in part to ensure that the options would not have a negative effect on system reliability. The BSER, including each of the building blocks, was determined to be feasible at reasonable costs over the timeframe proposed here. Further, under the Clean Air Act the states are given the flexibility to design state plans that include any measure or combination of measures to achieve the required emission limitations. States are not required to use each of the measures that the EPA determines constitute the BSER or use those measures to the same degree or extent that the EPA determines is feasible at a reasonable cost. Thus, each state has the flexibility to choose the most cost-effective measures given that state's energy profile and economy, as long as the state achieves the reductions necessary to meet its goal. Many market-based approaches which states may choose reduce the costs of compliance. They can allow certain units that are seldom used to remain in operation if they are needed for reliability purposes. Multi-state approaches also reduce costs and stress on the grid and so can help to reduce any concern about electricity reliability.

States may choose measures that would ease pressures on system reliability. This is true for many demand-side management approaches, including programs to encourage end-use energy efficiency, distributed generation, and combined heat and power, which actually reduce demand for centrally generated power and thus relieve pressure on the grid.

The EPA is proposing a 10-year period over which to achieve the full required CO_2 reductions, and we would expect this to further relieve any pressure on grid reliability. This relatively long planning and implementation period provides states with substantial flexibility regarding methods and timing of achieving emission reductions.

The EPA's supporting analysis for this rule includes an examination of the effects of the rule on regional resource adequacy.[271] The EPA's analysis looked at the types of changes in the generation fleet that were projected to occur through retirements, additional generation and energy efficiency. The analysis did not raise concerns over regional resource adequacy. The EPA further examined how the policy options impacted the flows and transfers of electricity that occur to meet reserve margins. None of the interregional changes in the policy cases suggested that there would be increases in flows that would raise significant concerns about grid congestion or grid management. Moreover, the time

[271] See the Resource Adequacy and Reliability Analysis TSD, available in the docket.

horizon for compliance with this rule will permit environmental and reliability planners to coordinate these changes and address potential concerns before they arise.

The EPA concludes that the proposed rule will not raise significant concerns over regional resource adequacy or raise the potential for interregional grid problems. The EPA believes that any remaining local issues can be managed through standard reliability planning processes. The flexibility inherent in the rule is responsive to the CAA's recognition that state plans for emission reduction can, and must, be consistent with a vibrant and growing economy and reliable, affordable electricity to support that economy. The EPA welcomes comments and suggestions on this issue.

VIII. State Plans

A. Overview

After the EPA establishes the state-specific rate-based CO_2 goals in the emission guidelines, as described in Section VII above, each state must then develop, adopt, and submit its state plan under CAA section 111(d). To do so, the state must first determine the emission performance level it will include in its plan, which entails deciding whether it will adopt the rate-based CO_2 goal set by the EPA or translate the rate-based goal to a mass-based goal.

The state must then establish an emission standard or set of emission standards, and, perhaps other measures, along with implementing and enforcing measures, that will achieve a level of emission performance that is equal to or better than the level specified in the state plan.

The state must then adopt the state plan through certain procedures, which include a state hearing. Within the time period specified in the emission guidelines (from as early as June 30, 2016 to as late as June 30, 2018, depending on the state's circumstances), the state must submit its complete state plan to the EPA. The EPA then must determine whether to approve or disapprove the plan. If a state does not submit a plan, or if the EPA does not approve a state's plan, then the EPA must establish a plan for the state.

As discussed in Section V.D of this preamble, in the case of a tribe that has one or more affected EGUs located in its area of Indian country, if the EPA determines that a CAA section 111(d) plan is necessary or appropriate, the EPA has the responsibility to establish a CAA section 111(d) plan for that area of Indian country where affected sources are located unless the tribe on whose lands an affected source (or sources) is located seeks and obtains authority from the EPA to establish a plan itself, pursuant to the Tribal Authority Rule.[272] The agency is soliciting comment on aspects of such CAA section 111(d) plans, as described in Section V.D of this preamble.

This section is organized into six parts. First, we discuss the types of plans that we propose states could submit. Second, we address timing for plan implementation and achievement of state emission performance goals for affected EGUs. Third, we discuss the proposed state plan approvability criteria. Fourth, we summarize the proposed components of an approvable state plan. Fifth, we address the proposed process and timing for submittal of state plans. Sixth, we identify several key considerations for states in developing and implementing plans, including: Affected entities with obligations under a plan; treatment of existing state programs; incorporation of renewable energy (RE) and demand-side energy efficiency (EE) programs in certain plans; quantification, monitoring, and verification of RE and demand-side EE measures; reporting and recordkeeping for affected entities; treatment of interstate effects; and projection of emission performance. Finally, we discuss a number of additional factors that could help states meet their CO_2 emission performance goals, and we note certain resources that are available to facilitate plan development and implementation. Additional discussion of some of the topics covered in this section can be found in the State Plan Considerations TSD and Projecting EGU CO_2 Emission Performance in State Plans TSD, both of which are in the rulemaking docket.

B. Approach

In this action, the EPA is proposing emission guidelines in the form of state-specific CO_2 emission performance goals. In addition, the EPA is proposing guidelines for states to follow in developing plans to establish and implement CO_2 emission standards for affected EGUs. The proposed plan guidelines include four general plan approvability criteria, twelve required components for a state plan to be approvable, the process and timing for state plan submittal and review, and the process and timing for demonstrating achievement of the CO_2 goals. These are described below.

The EPA recognizes that each state has different state policy considerations—including varying emission reduction opportunities and existing state programs and measures—and that the characteristics of the electricity system in each state (e.g., utility regulatory structure, generation mix, electricity demand) also differ. The agency also anticipates—and supports—states' commitments to a wide range of policy preferences that could encompass those of states like Kentucky, West Virginia and Wyoming seeking to continue to feature significant reliance on coal-based generation; states like Minnesota, Colorado, California and the nine RGGI states seeking to build on actions and policies they have already undertaken; and states like Washington and Oregon seeking to integrate sustainable forestry and renewable energy strategies. The proposed plan guidelines provide states with options for establishing emission standards in a manner that accommodates a diverse range of state approaches. Each state will have significant flexibility to determine how to best achieve its CO_2 goals in light of its specific circumstances, including addressing concerns particular to the state, such as employment transition issues, as it designs and implements its plan over multiple years. As an example, the RGGI states' implementation of their mass-based emission budget trading program raises proceeds through allowance auctions and uses those proceeds to advance programs promoting and expanding end-use energy efficiency. States could address analogous priorities, such as employment transition, through a similar mechanism.

The proposed plan guidelines would also allow states to collaborate and to develop plans that provide for demonstration of emission performance on a multi-state basis, in recognition of the fact that electricity is transmitted across state lines, and that state measures may impact, and may be explicitly designed to reduce, regional EGU CO_2 emissions. The EPA also recognizes that multi-state collaboration would likely offer lower-cost approaches to achieving CO_2 emission reductions. With this in mind, we are proposing to provide states with additional time to submit complete plans if they do so as part of a multi-state plan, and we solicit comment on other potential mechanisms for fostering multi-state collaboration.

1. State Plan Approaches

a. Overview

Although state CAA section 111(d) plans must assure that the emission performance level is achieved through

[272] See 40 CFR 49.1 to 49.11.

reductions at the affected sources, we believe that different types of state plans could be constructed that make use of the diversity of measures available to achieve CO_2 emission reductions. Based on the EPA's outreach efforts, it is clear that states are considering different types of plans.

Three important issues in the design of state plans include: (1) Whether the plan should require the affected EGUs to be subject to emission limits that assure that the emission performance level is achieved, or instead, whether the plan could rely on measures, such as renewable energy (RE) or demand-side energy-efficiency (EE), to assure the achievement of part of the emission performance level; (2) whether the responsibility for all of the measures other than emission limits should fall on the affected EGUs, or, instead, could fall on entities other than affected EGUs; and (3) whether the fact that requiring all measures relied on to achieve the emission performance level to be included in the state plan renders those measures federally enforceable. These issues and the EPA's proposed approach are addressed in detail in the sections that follow.

The EPA is proposing that all measures relied on to achieve the emission performance level be included in the state plan, and that inclusion in the state plan renders those measures federally enforceable.

In light of current state programs, and of stakeholder expressions of concerns over the above-noted issues, including legal enforcement considerations, with respect to those programs, the EPA is proposing to authorize states either to submit plans that hold the affected EGUs fully and solely responsible for achieving the emission performance level, or to submit plans that rely in part on measures imposed on entities other than affected EGUs to achieve at least part of that level, as well as on measures imposed on affected EGUs to achieve the balance of that level. The EPA requests comment on this proposed approach, as opposed to the approach under which state plans simply would be required to hold the affected EGUs fully and solely responsible for achieving the emission performance level.

In addition, the EPA is soliciting comment on several other types of state plans that may assure the requisite level of emission performance without rendering certain types of measures federally enforceable and that limit the obligations of the affected EGUs.

b. Portfolio Approach

In assessing the types of state plans to authorize, the EPA reviewed existing state programs that reduce CO_2 emissions from fossil fuel-fired power plants. Existing state programs are particularly informative for this purpose in light of the fact that CAA section 111(d) gives states the primary responsibility for designing their own state plans for submission to the EPA. Many of these existing state programs, as summarized above, include measures such as renewable energy (RE) and demand-side energy efficiency (EE) programs, which impose responsibilities on a range of entities, including state agencies, for assuring implementation of actions that result in reduced utilization of, and therefore reduced emissions from, fossil fuel-fired EGUs, and do not impose legal responsibilities for those emission reductions on the EGUs themselves.

In addition, during the EPA's extensive outreach efforts, many stakeholders expressed concern over the extent of responsibility that fossil fuel-fired EGUs would be required to bear for the required emission reductions, in particular, those associated with RE and demand-side EE measures. These stakeholders recommended that the EPA authorize states to achieve emission reductions from RE and demand-side EE measures by imposing requirements on entities other than fossil fuel-fired EGUs, and without imposing legal responsibility for these emission reductions on those EGUs.

Accordingly, the EPA is proposing to authorize a state plan to adopt what we refer to as a ''portfolio approach,'' in which the plan would include emission limits for affected EGUs along with other enforceable measures, such as RE and demand-side EE measures, that reduce CO_2 emissions from affected EGUs. Under this approach, it would be all of the measures combined that would be designed to achieve the required emission performance level for affected EGUs as expressed in the state goal. Under this approach, the emission limits enforceable against the affected EGUs would not, on their own, assure, or be required to assure, achievement of the emission performance level. Rather, the state plan would include measures enforceable against other entities that support reduced generation by, and therefore CO_2 emission reductions from, the affected EGUs. As noted, these other measures would be federally enforceable because they would be included in the state plan. A portfolio approach could be used for state plans that establish the emission performance level on either an emission rate basis or a mass emissions basis.

In addition, a portfolio approach could either be what we refer to as ''utility-driven'' or ''state-driven,'' depending on the utility regulatory structure in a state. Under a utility-driven approach, a state plan may include, for example, measures implemented consistent with a utility integrated resource plan, including both measures that directly apply to affected EGUs (e.g., repowering or retirement of one or more EGUs) as well as RE and demand-side EE measures that avoid EGU CO_2 emissions.[273] Under a state-driven approach, the measures in a state plan would include emission standards for affected EGUs, as well as requirements that apply to entities other than affected EGUs, for example, renewable portfolio standards (RPS) or end-use energy efficiency resource standards (EERS), both of which often apply to electric distribution utilities.[274]

c. Obligations on Affected EGUs

The EPA is proposing to authorize state plans to adopt the portfolio approach and is proposing to interpret the CAA as allowing that approach, as described in more detail below. CAA section 111(d)(1) would certainly allow state plans to require the affected EGUs to be the sole entities legally responsible for achieving the emission performance level. The EPA is also soliciting comment on whether it can reasonably interpret CAA section 111(d)(1) to allow states to adopt plans that require EGUs and other entities to be legally responsible for actions required under the plan that will, in aggregate, achieve the emission performance level.

We note that some existing state programs, such as RGGI in the northeastern states, do impose the ultimate responsibility on fossil fuel-fired EGUs to achieve the required emission reductions, but are also designed to work either concurrently, or in an integrated fashion, with RE and demand-side EE programs that reduce the cost of meeting those emission limitations. These existing programs offer a possible precedent for another type of CAA section 111(d) state plan. Such a plan approach could rely on CO_2 emission standards enforceable against affected EGUs—whether in the form of

[273] In the case of a utility-driven portfolio approach, the vertically integrated electric utility implementing portfolio measures is also the owner and operator of affected EGUs.

[274] A state-driven portfolio approach is more likely in states that have instituted electricity sector restructuring, where electric utilities have typically been required by states to divest electric generating assets.

emission rate or mass limits—to ensure achievement of the required emission performance level, but also include enforceable or complementary RE and demand-side EE measures that lower cost and otherwise facilitate EGU emission reductions. Depending on the type of plan, these RE and demand-side EE measures could either be enforceable components of the plan (that is, the states could require affected EGUs or other affected entities to invest in RE or in demand-side EE programs) or be complementary to the plan. In this manner, RE and demand-side EE measures could be a major component of a state's overall strategy for reducing EGU CO_2 emissions at a reasonable cost.

It should be noted that state plan approaches that impose legal responsibility on the affected EGUs to achieve the full level of required emission performance could incorporate RE and demand-side EE measures regardless of whether the emission standards that those plans apply to the affected EGUs take the form of an emission rate or a mass limit. Plans with rate-based emission limits could incorporate enforceable RE and demand-side EE measures by adjusting an EGU's CO_2 emission rate when demonstrating compliance through either an administrative adjustment by the state or use of a tradable credit approach. (These actions would need to be enforceable components of a state plan to facilitate EGU compliance with emission rate limits and ensure that actions are properly quantified, monitored, and verified.) A state plan that imposes a mass limit on affected EGUs that is sufficiently stringent to achieve the emission performance level would not need to include RE or demand-side EE measures as an enforceable component of the plan to assure the achievement of that performance level. The mass limit itself would suffice. However, the state may wish to implement RE and demand-side EE measures as a complement to the plan to support achievement of the mass limit at lesser cost.

d. Federal Enforceability

Another concern expressed by some stakeholders is that including RE and demand-side EE measures in state plans would render those measures federally enforceable and thereby extend federal presence into areas that, to date, largely have been the exclusive preserve of the state and, in particular, state public utility commissions and the electric utility companies they regulate. These stakeholders suggest that states could rely on RE and demand-side EE programs as complementary measures to reduce costs for, and otherwise facilitate, EGU emission limits without including those measures in the CAA section 111(d) state plan. Under this suggested approach, the EGU emission limits would be federally enforceable, but RE and demand-side EE measures would serve as complementary measures and would not be enforceable under federal law; instead, they would remain enforceable under state law. According to stakeholders, those types of state programs, particularly because they are well-established, can be expected to achieve their intended results. Thus, they suggest that the states could conclude that those RE and demand-side EE measures would be beneficial in assuring the achievement of the required emission performance level by the affected EGUs specified in the CAA section 111(d) state plan, even without including those measures in the plan.

e. Plans With State Commitments

As another vehicle for approving CAA section 111(d) plans for states that wish to rely on state RE and demand-side EE programs but do not wish to include those programs in their state plans, the EPA requests comment on what we refer to as a ''state commitment approach.'' This approach differs from the proposed portfolio approach, described above, in one major way: Under the state commitment approach, the state requirements for entities other than affected EGUs would not be components of the state plan and therefore would not be federally enforceable. Instead, the state plan would include an enforceable commitment by the state itself to implement state-enforceable (but not federally enforceable) measures that would achieve a specified portion of the required emission performance level on behalf of affected EGUs. The agency requests comment on the appropriateness of this approach. The agency also requests comment on the policy ramifications of the following: Under this approach, the state programs upon which the state bases its commitment may, in turn, rely on compliance by third parties, and if those state programs fail to achieve the expected emission reductions, the state could be subject to challenges—including by citizen groups—for violating CAA requirements and, as a result, could be held liable for CAA penalties.

We also solicit comment on a variation of this state commitment plan approach that is also designed to address stakeholder concerns, noted above, about imposing sole legal responsibility on affected EGUs for achieving the emission performance level. With this variation, the state plan would in effect shift a portion of that responsibility to the state, in the following manner: The state plan would impose the full responsibility for achieving the emission performance level on the affected EGUs, but the state would credit the EGUs with the amount of emission reductions expected to be achieved from, for example, RE or demand-side EE measures. The state would then assume responsibility for that credited amount of emission reductions in the same manner as the state commitment plan approach discussed above. We solicit comment on whether, if the EPA were to conclude that CAA section 111(d) requires state plans to include standards of performance applicable to affected EGUs that achieve the emission performance level, this type of state plan would meet that requirement while also assuring those EGUs an important measure of support.

f. Legal Issues

The EPA is proposing to interpret the relevant provisions in CAA section 111 to authorize state plans that achieve emissions reductions from affected EGUs by means of the portfolio approach. CAA section 111(d)(1) requires each state to submit a plan that ''(A) establishes standards of performance for any existing source [for certain air pollutants] . . . and (B) provides for the implementation and enforcement of such standards of performance.'' CAA section 111(a)(1) defines a ''standard of performance'' as ''a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction . . . adequately demonstrated.''

These provisions make clear that emission limits that are enforceable against affected EGUs appropriately belong in state plans because they clearly are ''standards of performance.'' However, the terms of CAA section 111(d)(1) do not explicitly address whether, in addition to emission limits on affected EGUs, state plans may include other measures for achieving the emission performance level. Nor do they address whether entities other than affected EGUs may be subject to requirements that contribute to reducing EGU emissions. Under the U.S. Supreme Court's 1984 decision in *Chevron U.S.A. Inc.* v. *NRDC,* where the statute leaves a gap, the agency has discretion to fashion an interpretation that is a reasonable construction of the statute.[275]

The EPA is proposing to interpret the phrases ''standards of performance for any existing source'' and ''the implementation and enforcement of such standards of performance'' to encompass and allow the various components of the portfolio approach. To the extent that a portfolio approach contains measures that are not standards of performance or do not implement or enforce such standards, the EPA is proposing to interpret CAA section 111 as allowing state CAA section 111(d) plans to include measures that are neither standards of performance nor measures that implement or enforce those standards, provided that the measures reduce CO_2 emissions from affected sources. These measures would also be federally enforceable if included in an approved plan.

The EPA's proposed interpretation is based, in part, on CAA section 111(d)'s requirement that states set performance standards ''for'' affected sources. Although ''for'' could be read as meaning that the standards must apply to affected sources, ''for'' is also reasonably interpreted to have a more capacious meaning: Standards (such as EE and RE standards) are reasonably considered to be ''for'' affected sources if they would have an effect on affected sources by, for example, causing reductions in affected EGUs' CO_2 emissions by decreasing the amount of generation needed from affected EGUs. Under this interpretation, and depending on the specific provisions in the state plan, renewable energy and demand-side energy efficiency requirements would be ''for'' fossil fuel-fired EGUs where such standards result in reduced CO_2 emissions from fossil fuel-fired EGUs, even if the standards do not apply directly to fossil fuel-fired EGUs.

The EPA also requests comment on another approach: Whether ''standards of performance for [affected sources]'' is reasonably read to include the emission performance level (i.e., the state goal) on grounds that the level is ''a standard for emissions'' because it is in the nature of a requirement that concerns emissions and it is ''for'' the affected sources because it helps determine their obligations under the plan.

Moreover, where the specific measures in the portfolio approach are not themselves a ''standard of performance,'' state plans may include measures that implement or enforce a standard of performance. For example, if the state's plan achieves the emission performance level through rate-based emission limits applicable to the affected sources, coupled with a crediting mechanism for RE and demand-side EE measures, we propose that RE and demand-side EE measures may be included in the plan as ''implement[ing]'' measures because they facilitate the sources' compliance with their standards of performance. We solicit comment on the extent to which measures such as RE and demand-side EE may be considered ''implement[ing]'' measures in state plans if they are not directly tied to emission reductions that affected sources are required to make through emission limits, and if they are requirements on entities other than the affected sources. In addition, the EPA proposes to interpret CAA section 111(d)(1) to allow state plans to include components of the portfolio approach that are measures that would reduce emissions from affected sources, even if those measures are neither ''standards of performance for existing sources'' nor measures ''for the implementation and enforcement of such standards of performance.'' There is no specific language in CAA section 111(d) or elsewhere in the Act that prohibits states from including measures other than performance standards and implementation and enforcement measures, provided that they reduce emissions from affected EGUs.

This interpretation is consistent with the principle of cooperative federalism, which is one of the foundational principles of the Clean Air Act and which supports providing flexibility to states to meet environmental goals (provided minimum CAA statutory requirements are met). This general principle, especially when combined with the statutory directive that CAA section 111(d) regulations shall establish procedures ''similar to that provided by section 110,'' supports an interpretation of CAA section 111(d) that allows states sufficient flexibility in meeting the state goal set under CAA section 111(d) to include in their CAA section 111(d) plans other measures (i.e., measures that are neither performance standards nor measures that enforce or implement performance standards). The EPA solicits comment on all aspects of its proposed interpretation that states have this flexibility in selecting measures for their state plans under CAA section 111(d).

An alternative interpretation of CAA section 111(d)(1) would suggest that the responsibility to achieve the state's required emission performance level must be assigned solely to affected EGUs. As described elsewhere in this preamble, there are a number of state-level CO_2 programs that take this approach while still taking advantage of low-cost reductions from RE and demand-side EE through the use of complementary measures. This alternative interpretation would be based on, for example: A determination that CAA section 111(d)(1) must be read as precluding a state plan from including measures that are neither standards of performance nor measures for the implementation or enforcement of such standards; an interpretation that the state's obligation to set performance standards ''for'' existing sources means that the standards must apply to affected EGUs and not to other entities; and an interpretation that measures ''for the implementation and enforcement of such performance standards'' do not include measures that are not intended or designed to assist affected EGUs in meeting the performance standards. The EPA requests comment on whether it must adopt this alternative interpretation. If so, the EPA also takes comment on whether there is a way, nonetheless, to allow states to rely on the portfolio approach to some extent and/or for some period of time.

We request comment on all of the interpretations discussed in this section generally, and on all legal issues under CAA section 111(d)(1) with respect to what measures can be included in a state plan and what entities must be legally responsible for meeting those measures.

g. Ongoing Applicability of CAA Section 111(d) State Plan

The EPA is proposing that an existing source that becomes subject to requirements under CAA section 111(d) will continue to be subject to those requirements even after it undertakes a modification or reconstruction. Under this interpretation, a modified or reconstructed source would be subject to both (1) the CAA section 111(d) requirements that it had previously been subject to and (2) the modified source or reconstructed source standard being promulgated under CAA section 111(b) simultaneously with this rulemaking. It should be noted that this proposal applies to any existing source subject to any CAA section 111(d) plan, and not only existing sources subject to the CAA section 111(d) plans promulgated under this rulemaking.

As noted above, a ''new source'' is defined under CAA section 111(a)(2) as ''any stationary source, the construction or modification of which is commenced after,'' in general, a proposed or final CAA section 111(b) rule becomes applicable to that source; and under

[275] *Chevron U.S.A., Inc.* v. *NRDC,* 467 U.S. 837, 842–44 (1984).

section 111(a)(6), an ''existing source'' is defined as ''any stationary source other than a new source.'' Under these definitions, an ''existing source'' that commences construction of a modification or reconstruction after the EPA has proposed or finalized a CAA section 111(b) standard of performance applicable to it, becomes a ''new source.'' However, CAA section 111(d) is silent on whether requirements imposed under a CAA section 111(d) plan continue for a source that ceases to be an existing source because it modifies or reconstructs. Specifically, CAA section 111(d)(1) provides that ''each State shall submit to the Administrator a state plan which (A) ''establishes standards of performance for any existing source'' but does not say whether, once the EPA has approved a state plan that establishes a standard of performance for a given source, that standard is lifted if the source ceases to be an existing source. Similarly, no other provisions of CAA section 111 address whether the imposition of a CAA section 111(b) standard on a modified or reconstructed source ends the source's obligation to meet any applicable CAA section 111(d) requirements.

Because CAA section 111(d) does not address whether an existing source that is subject to a CAA section 111(d) program remains subject to that program even after it modifies or reconstructs, the EPA has authority to provide a reasonable interpretation, under the Supreme Court's decision in *Chevron U.S.A. Inc.* v. *NRDC,* 467 U.S. 837, 842–844 (1984). The EPA's interpretation is that under these circumstances, the source remains subject to the CAA section 111(d) plan, for two reasons. The first is to assure the integrity of the CAA section 111(d) plan. The EPA believes that many states will develop integrated plans that include all of their EGUs, such as rate- or mass-based trading programs. Uncertainty about whether units would remain in the program could be very disruptive to the operation of the program. The second reason is to avoid creating incentives for sources to seek to avoid their obligations under a CAA section 111(d) plan by undertaking modifications. The EPA is concerned that owners or operators of units might have incentives to modify purely because of potential discrepancies in the stringency of the two programs, which would undermine the emission reduction goals of CAA section 111(d).

The EPA invites comments on this interpretation of CAA section 111(d)(1), including whether this interpretation is supported by the statutory text and whether this interpretation is sensible policy and will further the goals of the statute. It should be noted that this interpretation is severable from the rest of this rulemaking, so that if the EPA revises this interpretation in the final rule or if the EPA adopts this interpretation in the final rule but it is invalidated by a Court, there would be no effect on the rest of this rulemaking.

2. Timing for Implementation and Achievement of Goals

This section describes proposed state plan requirements related to the timing of achieving emission performance goals, including performance demonstrations, performance periods, and interim progress milestones.

As previously discussed, the goals are derived from application of four ''building blocks.'' The EPA has based the application of some of these measures to reduce CO_2 emissions, particularly blocks 3 (expansion of cleaner generating capacity) and 4 (increasing demand-side energy efficiency), on forward-looking, longer-term assumptions. For example, the EPA expects technologies to reduce carbon emissions to more fully develop over time and acknowledges the cumulative effects of implementation of EE programs and addition of RE generating capacity over time. Therefore, the EPA is not proposing to require each state to meet its full, final goal immediately, but rather to meet it by 2030. The EPA realizes, however, that states can achieve emission reductions from those and other measures in the short-term. Therefore, the EPA is proposing that states begin meeting interim goals, beginning in 2020. The EPA also believes that timing flexibility in implementing measures provides significant benefits that allow states to develop plans that will help states achieve a number of goals, including: Reducing cost, addressing reliability concerns, and addressing concerns about stranded assets. Therefore, the EPA is also proposing to allow states flexibility to define the trajectory of emission performance between 2020 and 2029, as long as the interim emission performance level is met on a 10-year average or cumulative basis and the 2030 emission performance level is achieved.

Section VIII.B.1.a of this preamble provides an overview of the proposals for state plan performance demonstrations and timing of emission reductions. Subsequent subsections include proposals for the start date for the interim goal performance period, the duration of the performance periods for the final and interim goals, interim progress milestone requirements, consequences if actual emission performance does not meet the state goal, and out-year requirements for states to maintain CO_2 emission performance levels over time consistent with the final goal. In Section VIII.B.2.f of this preamble, the agency also requests comment on alternative requirements aimed at continued emission performance improvement after 2029. In Section VIII.B.2.g of this preamble, the EPA proposes flexibility for states to change from mass-based to rate-based goals in different performance periods and, in Section VIII.B.2.h, we solicit comment on planning requirements that match the option of alternative, less stringent state goals.

a. Performance Demonstrations and Timing of Emission Reductions

As described previously, the agency is proposing final state-specific goals (specified in Table 8) that represent emission rates to be achieved by 2030, as well as interim goals, to be achieved on average over the 10-year period from 2020–2029. The agency is also proposing that emission performance levels consistent with the final state-specific goals be maintained after 2030.

This relatively long planning and implementation period provides states with substantial flexibility regarding methods and timing of achieving emission reductions. States may wish to make adjustments to their implementation approaches along the way, or as conditions change may need to make adjustments to ensure that their plans achieve the goals as intended. As a result, the agency envisions that the EPA, states, and affected entities will have an ongoing relationship in the course of implementing this program.

The EPA proposes that a state plan must demonstrate projected achievement of the emission performance levels in the plan, and these emission performance levels must be equivalent to or better than the interim and final goals established by the EPA. Specifically, the state plan must demonstrate that the projected emission performance of affected EGUs in the state will be equivalent to or better than the applicable interim goal during the 2020–2029 period, and equivalent to or better than the applicable final goal during the year 2030. The state plan must identify requirements that continue to apply after 2030 and are likely to maintain continued emission performance by affected EGUs that meets the final goal; however, quantitative projections of emission performance by affected EGUs beyond 2030 would not be required by this rule under the proposed approach. Instead, the EPA proposes that the state plan would be considered to provide for maintenance of emission performance consistent with the final goal if the plan measures used to demonstrate achievement of the final goal by 2030 will continue in force and not sunset.

In addition to demonstrating that projected plan performance will meet the interim and final state goals, the EPA proposes that state plans must contain requirements for tracking actual plan performance during implementation. For plans that do not include enforceable requirements for affected EGUs that ensure achievement of the full level of required emission performance and interim progress, the state plans would be required to include periodic program implementation milestones and emission performance checks, and include corrective measures to be implemented if mid-course corrections are necessary. The state plan would provide for continued tracking of emission performance after 2030, and for corrective measures if the emission performance of affected EGUs in the state did not continue to meet the 2030 final goal during any three-year performance period.

The rationale for this approach is that it would ensure that states design their plans in a way that considers both the interim and final goals. If only the interim goal were considered, a state plan might not be sufficient to achieve the final goal.[276]

The agency requests comment on a second option in which, in addition to submitting a plan demonstrating emission performance through 2030, states would be required to make a second submittal in 2025 showing whether their plan measures would maintain the final-goal level of emission performance over time (as further described below). If not, the state submittal would be required to strengthen or add to measures in the state plan to the extent necessary to maintain that level of performance over time.

The EPA also requests comment on whether 2025, or an earlier or later year, would be the optimal year for a second plan submittal under the second option.

b. Start Date for Performance Period for Interim Goal

A performance period is a period for which the state plan must demonstrate that the required emission performance level will be met. The EPA proposes a start date of January 1, 2020, for the interim goal plan performance period.[277] This date would be the beginning of the 10-year period for which a state must demonstrate that the projected emission performance level of affected EGUs in the state, on average, will be equivalent to or better than the applicable interim goal. The agency generally requests comment on the appropriate start date and rationale.

In considering the start date, it is relevant to consider the due dates for state plan submittals and the amount of time available for program implementation by the start date. January 2020 is 3.5 years from the proposed June 2016 deadline for initial plan submittals, 2.5 years from the proposed June 2017 extended deadline for complete plans from states not participating in a multi-state plan, and 1.5 years from the proposed June 2018 extended deadline for complete plans from states participating in a multi-state plan. The EPA suggests that affected entities may have greater lead time for compliance than might be implied by the plan submittal dates referenced above. Affected entities will have knowledge of state requirements as they are adopted, and the state must adopt rules and requirements in advance of submitting its complete plan to the EPA. Also, as explained in detail in subsection c, states may choose a different emission performance improvement trajectory from that which the EPA assumes for purposes of calculating state goals, achieving lesser levels of performance in early years and more in later years, provided, of course, that the interim 10-year average requirement is met.

The EPA proposes that a 2020 start date for the interim goal plan performance period is achievable in light of the following additional considerations. First, existing state programs will play a role in helping to achieve this rule's proposed emission performance levels. Second, in advance of this proposal, many states already were contemplating design of strategies that would achieve CO_2 emission reductions equivalent to those that could be required by CAA section 111(d) emission guidelines. Third, for inclusion in the building blocks, the EPA considered only those emission abatement measures that are technically feasible and broadly applicable, and can provide reductions in CO_2 emissions from affected EGUs at reasonable cost.

For example, the EPA expects that many EGUs will meet their requirements in part by implementing heat rate improvements, and those actions may be undertaken promptly. The plant operations and maintenance (O&M) and engineering solutions used to improve heat rates at existing EGUs have long been commercially available and have been implemented at EGUs for many years. Further, the relatively modest capital costs (average $100/kW) and significant fuel savings associated with a suite of heat rate improvement (HRI) methods result in this measure being a low-cost approach to reducing CO_2 emissions from existing EGUs. HRI ''best practices'' (e.g., installation of modern control systems, operator training, smart soot blowing) are the least-cost HRI methods and can be applied quickly, without lengthy EGU outages. The somewhat more costly HRI ''upgrades'' (e.g., steam turbine upgrade, boiler draft fan/driver upgrade) may require modest EGU outages to implement, but have also been applied on numerous EGUs to improve or maintain performance. Drawing on the power sector's extensive experience with HRI methods, and the many existing supply chains already supporting these methods, the EPA expects that it would be feasible to implement HRI projects (i.e., building block 1) by 2020.

Dispatch changes, which are largely driven by the variable cost of operating a given EGU, occur on an hourly basis in the power sector. The average availability factor for NGCCs in the U.S. generally exceeds 85 percent, and can exceed 90 percent for selected groups.[278] In addition, the existing natural gas pipeline and electricity transmission networks are already connected to every existing NGCC facility, and can support aggregate operation of the NGCC fleet at 70 percent (or above) at the state level, or can be reasonably expected to do so in the time frame for compliance with this rule. Therefore, building block 2, which represents shifting of generation from steam fossil EGUs to existing NGCCs, is a viable method for providing CO_2

[276] The 2020–2029 interim goal is expressed as a 10-year average emission rate to provide states with flexibility in designing their plans. Due to the potential for continued end-use energy efficiency improvements, the 2029 four-building-block BSER-based level is a more stringent level than the 2020–2029 average four-building-block BSER-based level. The purpose of the final goal is to ensure that each state ultimately achieves the emission performance level for affected EGUs that is achievable by 2029. Without the final goal, it is possible that a state could achieve the 2020–2029 interim goal but not achieve the 2030 final goal.

[277] The start date for a plan performance period must match the start date of the corresponding state emission performance goal. If a start date other than January 2020 were selected, the EPA would recompute the state goals consistent with the selected start date.

[278] Source: NERC, 2008–2012 Generating Unit Statistical Brochure.

emission reductions at existing EGUs by the 2020 compliance start date.

Building Block 3 is based on shifting generation from affected fossil units to new renewable energy generating capacity, which is added over time, and new or preserved nuclear capacity, all of which is expected to be in place by 2020 (see the GHG Abatement Measures TSD for more information).

Finally, there is considerable experience with the states and the power sector in designing and implementing demand-side energy efficiency improvement strategies and programs. It is also well accepted that such improvements can achieve reductions in CO_2 emissions from existing EGUs at a reasonable cost. Building block 4 represents a feasible pathway for reducing utilization of carbon-emitting EGUs by implementing improvements in demand-side energy efficiency. This building block is based on a ''best practices'' scenario where all states achieve a level of performance—matching a level achieved or committed to by twelve leading states—of 1.5 percent annual incremental electricity savings as a percentage of retail sales. For the best practices scenario, all states achieve this level of performance no later than 2025, with leading states reaching this level sooner. Each state's current level of performance is taken into account, with states achieving lower levels of performance being allowed more time to reach the best practice level.

c. Duration of Performance Periods for Final and Interim Goals

The EPA recognizes that a state's circumstances and choice of emission reduction strategies may affect the timing of CO_2 emission performance improvement within a multi-year planning period. States can be expected to select various combinations of measures and those measures may vary in the time needed to reach full implementation. The agency recognizes that certain emission reduction measures and programs (e.g., heat rate improvements) are generally easier to implement in the near term, while others (e.g., renewable portfolio standards, demand-side energy efficiency programs) may require several years to implement because of the time necessary to establish the proper infrastructure if a state does not already have such programs in place. Though some states have already implemented such programs that are achieving results, other states may have to establish them for the first time. New single and multi-state programs, as well as existing single and multi-state programs that are adding or revising measures, may need time for implementation to achieve the required level of emission performance.

As described in Section VII of the preamble, the EPA is proposing state-specific CO_2 emission performance goals in a multi-year format to provide states with flexibility for the timing of programs and measures that improve EGU emission performance, while ensuring an overall level of performance consistent with application of the BSER. Specifically, the agency is proposing the state-specific goals (shown in Table 8) which represent emission rates to be achieved by 2030 (final goal) and emission rates to be achieved on average over the 2020–2029 period (the interim goal).

The EPA proposes the following as the preferred option for the final and interim goal performance periods. As further explained below, this option reflects three main objectives: (1) Provide states with timing flexibility during the interim goal period to accommodate differences in state adoption processes and types of state programs, (2) ensure that state plans are designed to achieve the final goal no later than 2030, and (3) provide flexibility for year-to-year variation in actual emission performance that may occur as the electricity system responds to economic fluctuations.

Interim goal—Projected plan performance demonstration: To be approvable, a state plan must demonstrate that the emission performance of affected EGUs will meet the interim emission performance level on average over the 2020–2029 period.

Interim goal—Actual plan performance check: In 2030, the emission performance of affected EGUs during the period 2020–2029 must be compared against the interim goal. (In addition, as described separately below, interim emission performance checks will occur during this 10-year period.)

Final goal—Projected plan performance demonstration: To be approvable, a state plan must demonstrate that the emission performance of affected EGUs will meet the final emission performance level no later than 2030, on a single-year basis.

Final goal—Actual plan performance check: Starting at the end of 2032, emission performance of affected EGUs must be compared against the final goal on a three-year rolling average basis (i.e., 2030–32, 2031–33, 2032–2034, etc.).

This proposed approach provides a 10-year performance period for the interim performance level. The 10-year period allows states flexibility for timing of program implementation as the state ramps up its programs to achieve the final performance level. Using the single year 2030 as the projected year for achievement of the final goal ensures that state plans are designed to achieve the final goal no later than 2030; providing a multi-year time frame for projected plan performance would inappropriately delay the requirement for a final-goal level of performance that the EPA's analysis shows is achievable at the end of the 10-year interim ramp-up period. Using 2030 also avoids overlap with the interim goal performance period. The rolling three-year performance periods for measuring actual plan performance against the final goal performance level are proposed in light of year-to-year variability in economic and other factors, such as weather, that influence power system operation and affect EGU CO_2 emissions. The choice of 2030–2032 avoids overlap with the 2020–2029 interim goal performance period.

For a rate-based plan, 2020–2029 emission performance is an average CO_2 emission rate for affected EGUs representing cumulative CO_2 emissions for affected EGUs over the course of the 10-year performance period divided by cumulative MWh energy output [279] from affected EGUs over the 10-year performance period, with rate adjustments for qualifying measures, such as end-use energy efficiency and renewable energy measures, as described in Section VIII.F.3. For a mass-based plan, 2020–2029 emission performance is total tons of CO_2 emitted by affected EGUs over the 10-year performance period.

The agency invites comment on this and other approaches to specifying performance periods for state plans.

d. Program Implementation Milestones and Tracking of Emission Performance

The EPA recognizes the importance of ensuring that, during the proposed 10-year performance period (2020–2029) for the interim goal, a state is making steady progress toward achieving the required level of emission performance. The EPA is proposing that certain types of state plans be required to have program implementation milestones to ensure interim progress, as well as periodic checks on overall emission performance leading to corrective measures if necessary.

Some types of plans are ''self-correcting'' in that they inherently

[279] For EGUs that produce both electric energy output and other useful energy output, there would also be a credit for non-electric output, expressed in MWh.

would assure interim performance and full achievement of the state plan's required level of emission performance through requirements that are enforceable against affected EGUs. One example is a state plan with a rate-based emission performance level that requires affected EGUs collectively to meet an emission rate consistent with the state's required emission performance level, and allows EGUs to comply through an emission rate averaging system. Another example is a plan that includes measures or actions (e.g., emission limits that apply to affected EGUs and ensure full plan performance) that take effect automatically if the plan's required emission performance level is not met, in accordance with a specified milestone. The EPA requests comment on whether there are other types of state plans that should be considered ''self-correcting.''

The EPA proposes that self-correcting plans need not contain interim milestones consisting of program implementation steps, because these state plans inherently require both interim progress and achievement of the full level of required emission performance in a manner that is federally enforceable against affected EGUs. Annual reporting of emission performance by the state, however, is required for all types of plans.

For plans that are not self-correcting, the EPA proposes that the state plan must identify periodic program implementation milestones (e.g., start of an end-use energy efficiency program, retirement of an affected EGU, or increase in portfolio requirements under a renewable portfolio standard) that are appropriate to the programs and measures included in the plan. If, during plan implementation, a state were to miss program implementation milestones in its plan, it would need to report the delay to the EPA, explain the cause, and describe the steps the state will take to accelerate subsequent implementation to achieve the planned improvements in emission performance. Depending on the severity of delay and the explanation, the EPA could ultimately evaluate actions under CAA authorities to ensure timely program implementation.

In addition, we propose that the state and the EPA would track state plan emission performance on an ongoing basis, with states reporting performance data to the EPA annually by July 1. During the interim performance period, beginning in 2022, the state would be required each year to include a comparison of emission performance achieved to performance projected in the state plan. Each comparison would cover the preceding two-year period. The EPA may also approve regular, periodic emission comparison checks with a different frequency or comparison period to reflect the design of a state's programs (e.g., compliance periods for EGUs under an emission limit).

A report and corrective measures would be required if an interim emission check showed that actual emission performance of affected entities was not within 10 percent of the performance projected in the state plan (i.e., for a rate-based plan, if the average emission rate of affected EGUs were 10 percent higher than plan projections, or for a mass-based plan, if collective emissions of affected EGUs were 10 percent higher than plan projections). In that event, the state would be required in its submission to explain reasons for the deviation (e.g., energy efficiency program not working as effectively as expected, prolonged extreme weather that had been unanticipated in electricity demand projections) and specify the corrective measures that will be taken to ensure that the required level of emission performance in the plan will be met. The state also would be required to implement those corrective measures as expeditiously as practical.

The agency proposes that states be given a choice regarding when to adopt into regulation the corrective measures that the state plan identifies for implementation in the event that state plan performance is deficient. First, the state could adopt corrective measures into regulation prior to plan submittal in a manner that enables the state to implement the measures administratively, without further legislation or rulemaking, if a performance deficiency occurs during plan implementation. This would expedite implementation of corrective measures once a deficiency is discovered. Second, the state could elect to wait to adopt into regulation the corrective measures identified in the plan until after a plan performance deficiency is discovered. The EPA proposes this choice in recognition of the fact that it may be challenging for states to fully adopt corrective measures in advance to address the possibility that their plan will not perform as projected. However, if a state makes the latter choice, the EPA proposes that the state must report the reasons for deficient performance and must implement corrective measures if actual emission performance was inferior to projected performance by eight percent or more (rather than 10 percent or more). The reason for the lower percentage trigger is to identify a gradually developing deficiency in plan performance earlier in time. Legislative and/or regulatory action to adopt corrective measures after a deficiency is discovered will take significant time. State processes to activate corrective measures should be triggered earlier if corrective measures are not adopted in regulation and ready to implement.

The EPA alternatively requests comment on whether states should be required to create legal authority and/or adopt regulations providing for corrective measures in developing the state plan. The agency requests comment generally on the conditions that should trigger corrective measure requirements. The agency also solicits comment on whether actual emission performance inferior to projected performance by ten percent (for plans with corrective measures adopted into regulation prior to complete plan submittal) is the appropriate trigger for requiring a state to report the reasons for deficient performance and to implement corrective measures. We are also soliciting comment on the range of five percent to fifteen percent. For plans without corrective measures adopted into regulation prior to complete plan submittal, the agency solicits comment on whether the proposed eight percent emission performance deviation trigger is appropriate. We also solicit comment on the range of five percent to ten percent.

The EPA proposes that the state will be required to compare actual emission performance achieved during the entire 10-year interim performance period (i.e., 2020–2029) against the interim goal. As noted above, beginning after 2032, the EPA proposes that the state be required to compare actual emission performance achieved against the final goal on a rolling three-year average basis (e.g., 2030–32, 2031–33, etc.). The EPA also requests comment on the milestone approach and emission performance checks outlined above in the context of the alternative 5-year performance period and the planning approach for alternative state goals, which is described below.

e. Consequences if Actual Emission Performance Does Not Meet State Goal

There are scenarios under which an approved state plan might fail to achieve a level of emission performance by affected EGUs that meets the state goal. Under some types of plans, a possible scenario is that despite successful plan implementation, emissions under the plan turn out to be higher than projected at the time of plan approval because actual economic conditions vary from economic assumptions used when projecting emission performance. State officials have raised the possibility that achieved emission performance might not meet projected performance if, for example, planned retirements of EGUs were postponed because severe weather produced greater-than-expected electricity generation needs. In addition, emissions could theoretically exceed projections because affected entities under a state plan did not fulfill their responsibilities, or because the state did not fulfill its responsibilities.

The EPA believes that the emission guidelines should specify the consequences in the event that actual emission performance under a state plan does not meet the applicable interim goal in 2020–2029, or does not meet the applicable final goal in 2030–2032 or later, because CAA section 111(d) is not specific on this point. The agency requests comment on how the consequences should vary depending on the reasons for a deficiency in performance.

Specifically, the agency requests comment on whether consequences should include the triggering of corrective measures in the state plan, or plan revisions to adjust requirements or add new measures. The agency also requests comment on whether corrective measures, in addition to ensuring future achievement of the state goal, should be required to achieve additional emission reductions to offset any emission performance deficiency that occurred during a performance period for the interim or final goal. This concept has been applied, for example, in the Acid Rain Program under Title IV of the CAA; a source that has sulfur dioxide emissions exceeding the emission allowances that it holds at the end of the period for demonstrating compliance is required subsequently to obtain additional emission reductions to offset its excess emissions.[280] The agency also requests comment on the process for invoking requirements for implementation of corrective measures in response to a state plan performance deficiency.

The EPA further requests comment on whether the agency should promulgate a mechanism under CAA section 111(d) similar to the SIP call mechanism in CAA section 110. Under this approach, after the agency makes a finding of the plan's failure to achieve the state goal during a performance period, the EPA would require the state to cure the deficiency with a new plan within a specified period of time (e.g., 18 months). If the state still lacked an approved plan by the end of that time period, the EPA would have the authority to promulgate a federal plan under CAA section 111(d)(2)(A).

f. Out-Year Requirements: Maintaining or Improving the Level of Emission Performance Required by the Final Goal

The agency is determining state goals for affected EGU emission performance based on application of the BSER during specified time periods. This raises the question of whether affected EGU emission performance should only be maintained—or instead should be further improved—once the final goal is met in 2030. This involves questions of goal-setting as well as questions about state planning. In this section, the EPA proposes that a state must maintain the required level of performance, and requests comment on the alternative of requiring continued improvement.

The EPA believes that Congress either intended the emission performance improvements required under CAA section 111(d) to be permanent or, through silence, authorized the EPA to reasonably require permanence. Other CAA section 111(d) emission guidelines set emission limits to be met permanently. Therefore, the EPA is proposing that the level of emission performance for affected EGUs represented by the final goal should continue to be maintained in the years after 2030. The EPA is proposing a mechanism for implementing this objective, and is taking comment on an alternative option.

As noted above, the EPA proposes that the state plan must demonstrate that plan measures are projected to achieve the final emission performance level by 2030. In addition, the state plan must identify requirements that continue to apply after 2030 and are likely to maintain affected EGU emission performance meeting the final goal; however, quantitative projections of emission performance beyond 2030 would not be required under the proposed option. Instead, the EPA proposes that the state plan would be considered to provide for maintenance of emission performance consistent with the final goal if the plan measures used to demonstrate projected achievement of the final goal by 2030 will continue in force and not sunset.[281] After implementation, the state would be required to compare actual plan performance against the final goal on a rolling three-year average basis starting in 2030, and to implement corrective measures if necessary.

The EPA also requests comment on an alternative approach to a state's pre-implementation demonstration that the final-goal level of performance will be maintained after 2030. Under this alternative, the state plan would be required to include projections demonstrating that emission performance would continue to meet the final goal for up to 10 years beyond 2030. This approach could be implemented through a second round of state plan analysis and submittals in 2025 to make the demonstration and strengthen or add measures if necessary. The EPA generally requests comment on appropriate requirements to maintain the emission performance of affected EGUs in years after 2030.

The EPA also requests comment on whether we should establish BSER-based state emission performance goals for affected EGUs that extend further into the future (e.g., beyond the proposed planning period), and if so, what those levels of improved performance should be. Under this alternative, the EPA would apply its goal-setting methodology based on application of the BSER in 2030 and beyond to a specified time period and final date. The agency requests comment on the appropriate time period(s) and final year for the EPA's calculation of state goals that reflect application of the BSER under this approach.

The EPA notes that CAA section 111(b)(1)(B) calls for the EPA, at least every eight years, to review and, if appropriate, revise federal standards of performance for new sources. This requirement provides for regular updating of performance standards as technical advances provide technologies that are cleaner or less costly. The agency requests comment on the implications of this concept, if any, for CAA section 111(d).

g. State Flexibility To Choose Mass-Based and Rate-Based Goals After 2029

The EPA proposes that states have flexibility to choose between a rate-

[280] CAA section 411(b).

[281] This is straightforward for plans with EGU emission limits that ensure the full level of performance required. For renewable energy programs, the agency suggests that the state could continue to require the renewable portfolio percentage level that was relied upon to demonstrate projected achievement of the final goal performance level in 2030. For plans that rely in part on end-use energy efficiency programs and measures, the EPA requests comment on what a state would need to require in its plan to show that performance will be maintained after 2030. End-use energy efficiency programs and measures often involve an annual energy savings requirement or goal, and some types require additional monetary expenditures each year to meet those savings requirements or goals.

based and mass-based performance level for each performance period. For example, if a state plan used a mass-based performance level for the 2020–2029 period, the state plan may still use a rate-based performance level for final goal performance periods, or vice versa.

A state that adopted a mass-based performance level for 2020–2029 would have two options for addressing any perceived need for emissions flexibility in light of anticipated electricity demand growth after 2029. The state either could adopt a rate-based performance level consistent with the final goal, or could adopt a mass-based performance level based on a translation of the rate-based final goal to a mass-based goal.

h. Planning Approach for Alternative State Goals

In Section VII, the EPA requests comment on alternative, five-year state emission performance goals for affected EGUs shown in Table 9. The alternative goals represent emission rates achievable on average during the 2020–2024 period, as well as emission rates to be achieved and maintained after 2024. These alternative goals are less stringent than the proposed goals in Table 8.

To accompany the alternative goals, the EPA requests comment on another approach for state plan performance periods. This approach would require state plans to demonstrate that the required interim emission performance level will be met on average by affected EGUs during the five-year 2020–2024 interim period, and that the alternative final goal be met no later than 2025. After plan implementation, actual emission performance would be compared with the alternative final goal on a three-year rolling average basis, starting with 2025–2027, in light of year-to-year variability in economic and other factors, such as weather, that influence power system operation and affect EGU CO_2 emissions.

In connection with the alternative state goals, for the years after 2027, the EPA requests comment on the same ''out-year'' issues and concepts for maintaining or improving emission performance over time that are described above in Section VIII.B.2.f. The EPA requests comment on whether a state plan should provide for emission performance after 2025 solely through post-implementation emission checks that do not require a second plan submittal, or whether a state should also be required to make a second submittal prior to 2025 to demonstrate that its programs and measures are sufficient to maintain performance meeting the final goal for at least 10 years. In addition, the agency requests comment on the appropriate date for any second state plan submittal designed to maintain emission performance after the 2025 performance level is achieved.

C. Criteria for Approving State Plans

The EPA is proposing to require the twelve plan components discussed in Section VIII.D of this preamble. We will evaluate the sufficiency of each plan based on the plan addressing those components and on four general criteria for a state plan to be approvable. The EPA proposes to use the combination of these twelve plan components and four general criteria to determine whether a state's plan is ''satisfactory'' under CAA section 111(d)(2)(A). First, a state plan must contain enforceable measures that reduce EGU CO_2 emissions. Second, these enforceable measures must be projected to achieve emission performance equivalent to or better than the applicable state-specific CO_2 goal on a timeline equivalent to that in the emission guidelines.[282] Third, EGU CO_2 emission performance under the state plan must be quantifiable and verifiable. Fourth, the state plan must include a process for state reporting of plan implementation (at the level of the affected entity), CO_2 emission performance outcomes, and implementation of corrective measures, if necessary. The EPA requests comments on all aspects of these general criteria and the twelve specific plan components described below.

The agency also notes that a CAA section 111(d) state plan is not a CAA section 110 state implementation plan (SIP). Although there are similarities in the two programs, approvability criteria for CAA section 111(d) plans need not be identical to approvability criteria for SIPs.

1. Enforceable Measures

In developing its plan, a state must ensure that the plan is enforceable and in conformance with the CAA. We are seeking comment on the appropriateness of existing EPA guidance on enforceability in the context of state plans under CAA section 111(d), considering the types of affected entities that might be included in a state plan.[283] This guidance serves as the foundation for the types of emission limits that the EPA has found can be enforced as a practical matter and sets forth the general principle that a requirement that is enforceable as a practical matter is one that is quantifiable, verifiable, straightforward, and calculated over as short a term as reasonable.

As discussed in section VIII.F.1, the EPA is seeking comment on whether the agency should provide guidance on enforceability considerations related to requirements in a state plan for entities other than affected EGUs (and if so, which types of entities). Also, as discussed in section VIII.F.4, the EPA intends to develop guidance for evaluation, monitoring, and verification (EM&V) of renewable energy and demand-side energy efficiency programs and measures incorporated in state plans.

A state plan must include enforceable CO_2 emission limits (either rate-based or mass-based) that apply to affected EGUs. As noted above, the EPA is proposing that a state plan may take a portfolio approach, which would include enforceable CO_2 emission limits that apply to affected EGUs as well as other enforceable measures, such as RE and demand-side EE measures, that avoid EGU CO_2 emissions and are implemented by the state or by another entity assigned responsibility by the state. As noted above, we are proposing that state plans are not required to impose emission limits on affected EGUs that in themselves fully achieve the emission performance level. However, we are seeking comment on whether, for state plans where emission limits applicable to affected EGUs alone would not assure full achievement of the required level of emission performance, the state plan must include additional measures that would apply if any of the other portfolio of measures in the plan are not fully implemented, or if they are, but the plan fails to achieve the required level of emission performance.[284]

The EPA recognizes that a portfolio approach may result in enforceable state plan obligations accruing to a diverse range of affected entities beyond affected EGUs, and that there may be challenges to practically enforcing against some such entities in the event of noncompliance. We request comment

[282] Flexibilities provided to states in meeting this general approvability criterion are discussed below in Section VIII.C.2., emission performance.

[283] Enforceability guidance includes:(1) September 23, 1987 memorandum and accompanying implementing guidance, ''Review of State Implementation Plans and Revisions for Enforceability and Legal Sufficiency,'' (2) August 5, 2004 ''Guidance on SIP Credits for Emission Reductions from Electric-Sector Energy Efficiency and Renewable Energy Measures,'' and (3) July 2012 ''Roadmap for Incorporating Energy Efficiency/Renewable Energy Policies and Programs into State and Tribal Implementation Plans, Appendix F.''

[284] This could include, for example, an expansion of the scope or an increase in stringency of the current measures in the plan, a second set of measures that avoid EGU CO_2 emissions, or emissions limits that apply to affected EGUs.

on all aspects associated with enforceability of a state plan and how to ensure compliance. We are also seeking comment on enforceability considerations under different state plan approaches, which is addressed below in VIII.F.1.

2. Emission Performance

The second criterion for approvability is that the projected CO_2 emission performance by affected EGUs (taking into account the impacts of plan measures that are associated with reducing utilization from affected EGUs) must be equivalent to, or better than, the required CO_2 emission performance level in the state plan. State plans that are projected to achieve an average CO_2 emission rate (expressed in lb CO_2/MWh) or tonnage CO_2 emission outcome by all affected EGUs equal to, or lower than, the required level of CO_2 emission performance in the plan would meet this approvability criterion.

We are proposing that states may demonstrate such emission performance by affected EGUs either on an individual state basis or jointly on a multi-state basis.

All of the emission reduction measures included in the agency's determination of the BSER reduce CO_2 emissions from affected EGUs. As a result, the EPA is not proposing that out-of-sector GHG offsets could be applied to demonstrate CO_2 emission performance by affected EGUs in a state plan.

However, emission limits for affected EGUs that are included in state plans could still include provisions that provide the ability to use GHG offsets for compliance with the emission limits, provided those emission limits would achieve the required level of emission performance for affected EGUs. We note that inclusion of such provisions would create a degree of uncertainty about the level of emission performance that would be achieved by affected EGUs when complying with the emission limit (as potentially would other flexibility mechanisms included in an emission limit). As a result, such emission limits would not be considered ''self-correcting'' as discussed above at Section VIII.B.2.d.

All existing state emission budget trading programs addressing GHG emissions include out-of-sector, project-based emission offsets, which may be used to cover a portion of the compliance obligation of affected sources. Other states may want to take a similar approach, for example, to incentivize GHG emission reductions from land use and agricultural waste management. How to address GHG offsets included in EGU emission limits when projecting emission performance under a state plan is addressed in the Projecting EGU CO_2 Emission Performance in State Plans TSD.

The ISO/RTO Council, an organization of electric grid operators, has suggested that ISOs and RTOs could play a facilitative role in developing and implementing region-wide, multi-state plans, or coordinated individual state plans. Existing ISOs and RTOs could provide a structure for achieving efficiencies by coordinating the state plan approaches applied throughout a grid region. Just as the ISO/RTO regions today share the benefits and costs of efficient EGU dispatch across state boundaries, there are significant efficiencies that could be captured by coordinating individual state plans or implementing multi-state plans within a grid region. Under one variant of this approach, states would implement a multi-state plan and jointly demonstrate CO_2 emission performance by affected EGUs across the entire ISO/RTO footprint. States with borders that cross the boundary of one or more ISO or RTO footprints would need to include multiple plan components that address affected EGUs in each respective ISO or RTO. The EPA is seeking comment on this idea. States that are outside the footprint of an ISO or RTO may benefit from consulting with other relevant planning authorities when preparing state plans. We are also requesting comment on this idea.

3. Quantifiable and Verifiable Emission Performance

The third criterion for approvability is that a state plan specify how the effects of each state plan measure will be quantified and verified. The EPA proposes that all plans must specify how CO_2 emissions from affected EGUs are monitored and reported. The EPA is proposing that both mass-based and rate-based plans must include CO_2 emission monitoring, reporting, and recordkeeping requirements for affected EGUs, as specified in the emission guidelines. A rate-based plan must also include monitoring, reporting, and recordkeeping requirements for useful energy output from affected EGUs (electricity and useful thermal output), as specified in the emission guidelines. With one exception, these proposed requirements are consistent with those in the proposed EGU Carbon Pollution Standards for New Power Plants. See 79 FR 1430–1519 (January 8, 2014). The exception is that we are proposing that useful energy output be measured in terms of net output rather than gross output, as discussed below.

For state plans that include other measures that avoid EGU CO_2 emissions, such as RE and demand-side EE measures, the state will also need to include quantification, monitoring, and verification provisions in its plan for these measures, which may vary depending on the types of requirements included in the specific plan, as specified in the emission guidelines. This may include, for example, quantification, monitoring, and verification of RE generation and demand-side EE energy savings under a rate-based approach.[285]

4. Reporting and Corrective Actions

The fourth criterion for approval is that a state plan must (i) specify a process for annual reporting to the EPA of overall plan performance and implementation (including compliance of affected entities with applicable emission standards) during the plan performance periods, and (ii) include a process and schedule for implementing corrective measures if reporting shows that the plan is not achieving the projected level of emission performance. We solicit comment on whether the latter process should include the adoption of new plan measures and subsequent resubmission of the plan to the EPA for review and approval, or whether the process should specify the implementation of measures that are already included in the approved plan in the event that the projected level of performance is not being achieved. We also solicit comment on the point at which such a process and schedule would be triggered, such as at the end of a multi-year plan performance period if emission performance is not met, or at specified interim stages within a multi-year plan performance period. For plans with self-correcting mechanisms, the agency is not proposing that requirements for corrective measures be included in the plan. All of these considerations are addressed in more detail above in Section VIII.B.2.

The agency is also proposing that a state plan specify appropriate periodic reporting requirements for each affected entity in a state plan that will be reported at least annually, electronically, and disclosed on a state database accessible by the public and the EPA. The EPA is requesting comment on the appropriate scope of these reporting requirements and whether the reports should also be directly submitted by the affected

[285] Considerations for quantification, monitoring, and verification of RE and demand-side EE measures are addressed in Section VII.F.4 of this preamble and in the State Plan Considerations TSD.

entities to the EPA, as well as to the state.

D. State Plan Components

The EPA is proposing that an approvable plan must meet the approvability criteria described above and include the twelve state plan components summarized below, consistent with additional specific requirements explained elsewhere in this notice. Plans must comply with the EPA framework regulations at 40 CFR 60.23–60.29, except as specified otherwise by these emission guidelines. These requirements apply both to individual state plans and multi-state plans.

For states wishing to participate in a multi-state plan, the EPA is proposing that only one multi-state plan would be submitted on behalf of all participating states. The joint submittal would be signed by authorized officials for each of the states participating in the multi-state plan and would have the same legal effect as an individual submittal for each participating state. The joint submittal would adequately address plan components that apply jointly for all participating states and for each individual state in the multi-state plan, including necessary state legal authority to implement the plan, such as state regulations and statutes. Because the multi-state plan functions as a single plan, each of the required plan components described below (e.g., plan performance levels, program implementation milestones, emission performance checks, and reporting) would be designed and implemented by the participating states on a multi-state basis.

We are also seeking comment on two additional options for multi-state plan submittals. These options could potentially provide states with flexibility in addressing contingencies where one or more states submit plan components that are not approvable. In such instances, these options would simplify EPA approval of remaining common or individual portions of a multi-state plan. These options might also address contingencies during plan development where a state fails to finalize its participation in a multi-state plan, with minimal disruption to the submittals of the remaining participating states.

First, the EPA is seeking comment on whether states participating in a multi-state plan should also be given the option of providing a single submittal—signed by authorized officials from each participating state — that addresses common plan elements. Individual participating states would also be required to provide individual submittals that provide state-specific elements of the multi-state plan. Both the common multi-state submittal and each individual participating state submittal would be required to address all twelve plan components described below (even if only through cross reference to either the common submittal or individual submittals, as appropriate). Under this approach, the combined common submittal and each of the individual participating state submittals would constitute the multi-state plan submitted for EPA review.

Second, the EPA is seeking comment on an approach where all states participating in a multi-state plan separately make individual submittals that address all elements of the multi-state plan. These submittals would need to be materially consistent for all common plan elements that apply to all participating states, and would also address individual state-specific aspects of the multi-state plan. Each individual state plan submittal would need to address all twelve plan components.

The EPA proposes that each plan must have the following twelve components, except as indicated otherwise for self-correcting plans:

1. Identification of Affected Entities (Affected EGUs and Other Responsible Parties)

A state plan must list the individual affected EGUs in the state that are subject to the plan and provide an inventory of CO_2 emissions from those units (for the most recent calendar year prior to plan submission for which data are available), and identify any other affected entities in a state plan with responsibilities for implementation and enforceable obligations under the plan.

2. Description of Plan Approach and Geographic Scope

The state plan must describe its approach and geographic scope, including whether the state will achieve its required level of CO_2 emission performance on an individual state basis or jointly through a multi-state demonstration.

3. Identification of State Emission Performance Level

The state plan must identify the state's proposed emission performance level, which will either be the rate-based CO_2 emission goal identified for the state in the emission guidelines or a translation of the rate-based goal to a mass-based goal.

A state plan must identify the rate-based or mass-based level of emission performance that must be met through the plan, (expressed in numeric values, including the units of measurement for the level of performance, such as pounds of CO_2 per net MWh of useful energy output or tons of CO_2). As noted, in the emission guidelines, the EPA will establish the state goal in the form of a CO_2 emission rate, and the state may, for its emission performance level, either adopt that rate or translate it into a mass-based goal. If the plan adopts a mass-based goal, the plan must include a description of the analytic process, tools, methods, and assumptions used to translate from the rate-based goal to the mass-based goal.

The EPA is proposing that multiple states could jointly demonstrate emission performance by affected EGUs. For these multi-state approaches, states would demonstrate emission performance by affected EGUs in aggregate with partner states. For states participating in a multi-state approach, the individual state performance goals in the emission guidelines would be replaced with an equivalent multi-state performance goal. For example, states taking a rate-based approach would demonstrate that all affected EGUs subject to the multi-state plan achieve a weighted average CO_2 emission rate that is consistent, in aggregate, with an aggregation of the state-specific rate-based CO_2 emission performance goals established in the emission guidelines that apply to each of the participating states. If states were taking a mass-based approach, participating states would demonstrate that all affected EGUs subject to the multi-state plan emit a total tonnage of CO_2 emissions consistent with a translated multi-state mass-based goal. This multi-state mass-based goal would be based on translation of an aggregation of the state-specific rate-based CO_2 emission performance goals established in the emission guidelines that apply to each of the participating states.

The EPA is seeking comment on two options for calculating a weighted average, rate-based CO_2 emission performance goal for multiple states. Under the first option, the weighted average emission rate goal for a group of participating states is computed using each state's emission rate goal from the emission guidelines and the quantity of electricity generation by affected EGUs in each of those states during the 2012 base year that the EPA used in calculating the state-specific goals. Different levels would be computed for the interim and final goals. This approach is consistent with the method used to calculate the state-specific, rate-based emission performance goals. However, it does not address the fact that the weighted average emission rate performance goal for multiple states may be influenced significantly by the weighting of electricity generation from affected EGUs in different states. This mix of generation among affected EGUs in different states could differ significantly during the plan performance periods from that during the 2012 base year.

Under the second option, the weighted average emission rate goal for a group of participating states is computed using each state-specific emission rate goal and the quantity of projected electricity generation by affected EGUs in each state. The calculation would be performed for the 2020 through 2029 period to produce a multi-state interim goal, and for 2030 to produce a multi-state final goal. This projection of electricity generation by affected EGUs would be for a reference case that does not include application of either the state-specific rate-based emission performance goals for the participating states or the requirements, programs, and measures included in the multi-state plan. This approach addresses the fact that the mix of generation among affected EGUs in different states could differ significantly during the plan performance periods from that during the 2012 base year. As a result, it would base the weighted average goal in part on the anticipated business-as-usual mix of generation by affected EGUs across the multiple states during the plan performance period. However, this approach could also significantly alter the weighted average performance goal based on projected retirements of affected EGUs in one or more states.

Under both options, the rate-based multi-state goal could be translated to a mass-based goal. These options, and the procedure for translation to a mass-based goal, are discussed in more detail in the Projecting EGU CO_2 Emission Performance in State Plans TSD.

We are requesting comment on whether, to assist states that seek to translate the rate-based goal into a mass-based goal, the EPA should provide a presumptive translation of rate-based goals to mass-based goals for all states, for those who request it, and/or for multi-state regions. As another alternative, the EPA could provide guidance for states to use in translating a rate-based goal to a mass-based goal for individual states and for multi-state regions. This could include information about acceptable analytical methods and tools, as well as default input assumptions for key parameters that will likely influence projections, such as electricity load forecasts and projected fossil fuel prices. Under this approach, the EPA might also provide a coordinating function in addressing the assumptions applied by multiple states within a grid region, acknowledging that assumptions about state programs across a broader grid region that are included in an analysis scenario may influence projections of CO_2 emissions by affected EGUs in one or more particular states in the grid region. The agency is seeking comment on the process for establishing mass-based emission goals, including the options summarized above for the EPA's and states' roles in the translation process.

Technical considerations involved in translating from rate-based goals to mass-based goals are discussed in detail in the Projecting EGU CO_2 Emission Performance in State Plans TSD. The TSD includes a discussion of possible acceptable analytical methods, tools, and key assumption inputs that will influence projections. The agency invites comment on these technical considerations.

4. Demonstration That the Plan Is Projected To Achieve the State's Emission Performance Level

A state plan must demonstrate that the actions taken pursuant to the plan are, when taken together, projected to achieve emission performance by affected entities that, on average, will meet the state's required emission performance level for affected EGUs during the initial 2020–2029 plan performance period, and will meet the required final emission performance level in 2030. This demonstration will include a detailed description of the analytic process, tools, and assumptions used to project future CO_2 emission performance by affected EGUs under the plan and the results of the analysis. Considerations related to projecting the emission performance of affected EGUs under a state plan are discussed in section VIII.F.7 and in the Projecting EGU CO_2 Emission Performance in State Plans TSD.

5. Milestones

As described in greater detail in Section VIII.B.2.d., state plans must include periodic programmatic milestones to show progress in program implementation if the plan is not self-correcting (i.e., does not inherently require both interim progress and the full level of required emission performance in a manner that is federally enforceable against affected EGUs). These programmatic milestones with specific dates for achievement should be appropriate to the programs and measures included in the plan.

In addition, the state plan demonstration will indicate the plan's intended trajectory of emission performance improvement. As described in Section VIII.B.2.d., each year during the interim performance period, beginning in 2022 the state must compare the collective emission performance achieved by affected entities in the state during the previous two-year period with performance projected in the state plan. If actual emission performance is not within 10 percent of original projections, the state must submit a report by the July 1 following the end of the two-year period (submitted as part of the state's annual report on plan performance described below in section VIII.D.10) to explain reasons for the deviation and specify the corrective actions that will be taken to ensure that the required level of emission performance in the plan will be met.

6. Corrective Measures

For a plan that does not include self-correcting mechanisms, the plan must also specify corrective measures that will be implemented if the state's progress in achieving its level of performance for affected EGUs falls short of what is projected under the plan, as well as a process and schedule for implementing any such measures. The agency requests comment on the amount of emission rate improvement or emission reduction that the corrective measures included in the plan must be designed to achieve (e.g., measures sufficient to address a 10 percent performance deficiency). The agency also seeks comment on whether the emission guidelines should establish a deadline for implementation of corrective measures (e.g., two years from the July 1 deadline described above for reporting the deficiency as part of the state's annual report on plan performance). Corrective measure provisions are discussed in more detail above in section VIII.B.2.d and in section VIII.B.2.f.

7. Identification of Emission Standards and Any Other Measures

A state plan must identify the affected entities to which each emission standard applies (e.g., individual affected EGUs, groups of affected EGUs, all the state's affected EGUs in aggregate, other affected entities that are not EGUs), as well as any implementing and enforcing measures for such standards, and describe each emission standard and the process for demonstrating compliance with it pursuant to state regulations or another legal instrument, including the schedule for compliance for each affected entity. In its proposed Carbon Pollution Standards (79 FR 1430–1519, January 8, 2014), the EPA proposed that the appropriate averaging time for an emission standard for new EGUs be no longer than 12 months. Similarly, the EPA proposes here that an appropriate averaging time for any rate-based emission standard for affected EGUs and/or other affected entities subject to a state plan is no longer than 12 months within a plan performance period and no longer than three years for a mass-based standard. We also solicit comment on longer and shorter averaging times for emission standards included in a state plan.

8. Demonstration That Each Emission Standard Is Quantifiable, Non-Duplicative, Permanent, Verifiable, and Enforceable

In developing its CAA section 111(d) plan, a state must ensure that its plan is enforceable and in conformance with the CAA. As discussed in section VIII.C.1, we are seeking comment on the appropriateness of existing EPA guidance on enforceability in the context of state plans under CAA section 111(d), considering the types of affected entities that might be included in a state plan.[286] This guidance serves as the foundation for the types of monitoring, reporting, and limits that the EPA has found can be, as a practical matter, enforced, and set forth the general principle that a requirement that is enforceable as a practical matter is one that is quantifiable, verifiable, straightforward and is calculated over as short a term as reasonable.

As discussed in section VIII.F.1, the EPA is seeking comment on whether the agency should provide guidance on enforceability considerations related to requirements in a state plan for entities other than affected EGUs (and if so, which types of entities). Also, as discussed in section VIII.F.4, the EPA intends to develop guidance for evaluation, monitoring, and verification (EM&V) of renewable energy and demand-side energy efficiency programs and measures incorporated in state plans.

For each emission standard, a plan must describe how it is quantifiable, non-duplicative, permanent, verifiable, and enforceable with respect to an affected entity. An emission standard is quantifiable if it can be reliably measured, using technically sound methods, in a manner that can be replicated. These issues are discussed further in Section VIII.F.4 and in the State Plan Considerations TSD.

An emission standard is non-duplicative with respect to an affected entity if it is not already incorporated in another state plan, except in instances where incorporated in another state as part of a multi-state plan. An example of a duplicative emission standard would occur where recognition of avoided CO_2 emissions from, for example, a wind farm, could be applied in more than one state's CAA section 111(d) plan, except in the case of a multi-state plan where recognition is assigned among states or emission performance is demonstrated jointly for all affected EGUs subject to the multi-state plan. This does not mean that measures in an emission standard cannot also be used for other purposes. For example, if a state wished to take credit for CO_2 emissions avoided due to electric generation from a new wind farm, those avoided emissions could be considered non-duplicative and included for purposes of CAA section 111(d), even if electric generation from that wind farm was also being used to generate renewable energy certificates (RECs) to comply with the state's RPS requirements. It also does not mean that a single affected entity could not be subject to similar emission standards in different state plans. For example, an affected entity might be an electric distribution utility that has a service territory that crosses state lines. This entity might be subject to a separate state demand-side EE requirement for electricity supplied in each of the states where it serves electricity customers. In this instance, the same company could be an affected entity subject to a different state demand-side EE requirement in each state plan, without these emission standards in each plan being considered duplicative. The EPA solicits comment on whether an emission reduction becomes duplicative (and therefore cannot be used for demonstrating performance in a plan) if it is used as part of another state's demonstration of emission performance under its CAA section 111(d) plan.

An emission standard is permanent if the standard must be met for each applicable compliance year or period, or replaced by another emission standard in a plan revision, or the state demonstrates in a plan revision that the emission standard is no longer necessary for the state to meet its required emission performance level for affected EGUs.

An emission standard is verifiable if adequate monitoring, recordkeeping and reporting requirements are in place to enable the state and the Administrator to independently evaluate, measure, and verify compliance with it. This is discussed further in Section VIII.F.4 and in the State Plan Considerations TSD. An emission standard is enforceable if: (1) It represents a technically accurate limitation or requirement and the time period for the limitation or requirement is specified, (2) compliance requirements are clearly defined, (3) the affected entities responsible for compliance and liable for violations can be identified, (4) each compliance activity or measure is practically enforceable in accordance with EPA guidance on practical enforceability (as discussed in Section VIII.F.1 of this preamble), and the Administrator and the state maintain the ability to enforce against violations and secure appropriate corrective actions pursuant to CAA sections 113(a)–(h).

9. Identification of Monitoring, Reporting, and Recordkeeping Requirements

The state plan must describe the CO_2 emission monitoring, reporting, and recordkeeping requirements for affected EGUs, including requirements for monitoring and reporting of useful energy output if a state plan is taking a rate-based approach. The EPA is proposing that each plan include monitoring, reporting, and recordkeeping requirements for CO_2 emissions and useful energy output (if applicable) that are materially consistent with the requirements specified in the emission guidelines. State plans with a rate-based form of the emission performance level must require affected EGUs to report hourly net energy output (including net MWh generation, and where applicable, useful thermal output) to the EPA on an annual basis.

Most affected EGUs already monitor CO_2 emissions under 40 CFR Part 75 and report the data using the EPA's Emission Collection and Monitoring Plan System (ECMPS), which would generally satisfy CO_2 emission reporting requirements under the proposed guidelines. However, we are seeking comment on two possible adjustments to the Part 75 Relative Accuracy Test Audit (RATA) requirements for steam EGU stack gas flow monitors that can affect reported CO_2 emissions. The first possible adjustment would be to require use of the most accurate RATA

[286] EPA guidance on enforceability includes: (1) September 23, 1987 memorandum and accompanying implementing guidance, "Review of State Implementation Plans and Revisions for Enforceability and Legal Sufficiency," (2) August 5, 2004 "Guidance on SIP Credits for Emission Reductions from Electric-Sector Energy Efficiency and Renewable Energy Measures," and (3) July 2012 "Roadmap for Incorporating Energy Efficiency/Renewable Energy Policies and Programs into State and Tribal Implementation Plans, Appendix F."

reference method for specific stack configurations, while the second possible adjustment would be to require a computation adjustment when an EGU changes RATA reference methods. The rationale for these possible adjustments is described further in the Part 75 Monitoring and Reporting Considerations TSD available in the docket.

We are also proposing monitoring and reporting protocols for net energy output under 40 CFR Part 75 that would allow the ECMPS to be used for purposes of meeting the net energy output reporting requirement. Affected facilities with multiple generators (e.g., combined cycle facilities) would be required to report the electric output from all generators. The proposed protocols include a default apportionment procedure for multi-EGU facilities under which the net generation of each EGU at the facility would be determined as the net generation of the facility multiplied by the ratio of the EGU's gross generation to the sum of the gross generation for all EGUs at the facility. (In the case of EGUs producing both electric energy output and useful thermal output, the apportionment procedure would include a thermal-to-electric energy conversion calculation as provided in the proposed EGU GHG NSPS regulations.[287]) We solicit comment on whether EGUs producing both electric energy output and useful thermal output should be required to report both electric and useful thermal output. In addition, the proposed protocols would allow facilities to use alternative apportionment procedures with EPA approval. We invite comment on the proposal for reporting of net rather than gross energy output and on the proposed protocols. Specifically, we are seeking comment on: Any existing protocols for reporting net output (FERC, NERC, etc.); electricity meter specifications; electricity meter quality assurance testing and reporting procedures; apportionment procedures for parasitic load at multi-unit facilities; treatment of externally provided electricity; and monitoring and quality assurance testing and reporting procedures for non-electric energy output at CHP units. (Options regarding these topics are discussed in the TSD mentioned above.) Also, consistent with the requests for comment in the proposed CAA section 111(b) GHG NSPS regulations for modified and reconstructed sources, we invite comment here on a range of two-thirds to 100 percent credit for useful thermal output in the final rule, or other alternatives to better align incentives with avoided emissions.

[287] 70 FR 1429–1519; January 8, 2014.

A state plan that contains other emission standards, in addition to emission limits applicable to affected EGUs, must include additional reporting and recordkeeping requirements related to these other measures. These reporting and recordkeeping requirements will consist of the data necessary for each affected entity to demonstrate compliance with its obligations. This could include, for example, reporting of MWh electricity savings achieved by an electric distribution utility under an end-use energy efficiency resource standard and utility compliance with requirements of the standard. These requirements might also include comparable reporting by an electric distribution utility of renewable energy certificates (RECs) held, or renewable energy purchased or generated, under a renewable energy portfolio standard, and compliance with the standard. This is discussed further in Section VIII.F.5 and the State Plan Considerations TSD.

The EPA is proposing that state plans must include a record retention requirement of ten years, and we request comment on this proposed timeframe.

10. Description of State Reporting

A state plan must provide that the state will submit reports to the EPA detailing plan implementation and progress, including the actions taken by the state, affected EGUs, and any other affected entities under the plan; the status of compliance by affected EGUs and any other affected entities with their obligations under the plan; current aggregate and individual CO_2 emission performance by affected EGUs during the reporting year and prior reporting years; and any additional measures applied under the plan during the reporting period. The state plan must describe the process, timing, and content for these reports. The EPA is proposing that an annual report is due no later than the July 1 following the end of the reporting year.

While some of the proposed reporting requirements such as reporting of EGU emissions (which can be done through existing reporting mechanisms) would not place additional burdens on states, others may require assembling information that is being reported under state programs into a single report. For example, in the case of a rate-based state plan that calls for adjusting the actual emission rate of the state's affected EGUs based on emissions avoided through renewable energy or end-use energy efficiency programs, the requirement for comparing actual plan performance against projected plan performance requires the state to incorporate information on results achieved by those programs each year. This emission performance comparison serves as the basis for showing either that a state plan is on track or that corrective measures are needed. Another reporting element is a list of facilities and their compliance status. The EPA is requesting comment on the appropriate frequency of reporting of the different proposed reporting elements, considering both the goals of minimizing unnecessary burdens on states and ensuring program effectiveness. In particular, the agency requests comment on whether full reports containing all of the report elements should only be required every two years.

In addition, the EPA is soliciting comment on whether these reports should be submitted electronically, to streamline transmission.

11. Certification of State Plan Hearing

A state plan must provide certification that a hearing on the state plan was held, a list of witnesses and their organizational affiliations, if any, appearing at the hearing, and a brief written summary of each presentation or written submission pursuant to the requirements of the EPA framework regulations at 40 CFR 60.23–60.29.

12. Supporting Material

The state must provide supporting material and technical documentation related to applicable components of the plan. In its plan, a state must adequately demonstrate that it has the legal authority for each implementation and enforcement component that it has included in its plan as part of a federally enforceable emission standard. A state can make such a demonstration by providing supporting material related to the state's legal authority used to implement and enforce each component of the plan, such as statutes, regulations, public utility commission orders, and any other applicable legal instruments.

A state plan must also provide analytical materials used in translating a rate-based goal to a mass-based goal (if a translation is included), analytical materials used in projecting emission performance that will be achieved through the plan, relevant implementation materials, and any additional technical requirements and guidance the state proposes to use to implement elements of the plan.

E. Process for State Plan Submittal and Review

1. Overview

Under the framework regulations, state plans would be due nine months after finalization of the emission guidelines. 40 CFR 60.23(a)(1). The President in his June 25, 2013 Memorandum specified that states should submit plans by June 30, 2016, which would provide states thirteen months. During the outreach process, many states expressed concern that this was not sufficient time to prepare and submit a state plan to the EPA. States commented that additional time was needed to accommodate, among other things, state legislative and rulemaking schedules, coordination among states involved in multi-state plans, coordination with third parties, and the complex technical work needed to develop a state plan. The EPA recognizes that state administrative procedures can be lengthy, some states may need new legislative authority, and states planning to join in a multi-state plan will likely need more than thirteen months to get necessary elements in place. Balanced against that concern, however, is the urgency of addressing carbon emissions and the fact that there are certain steps we believe states can take within thirteen months to set themselves on a clear path to adoption of a complete plan. Therefore, the EPA is proposing a plan submittal process with a submittal date of June 30, 2016 (thirteen months after the expected finalization date of the emission guidelines), which provides additional time to submit a complete plan to the EPA after June 30, 2016, when justified. Part of that justification would include the state's demonstration of having taken meaningful steps during the first thirteen months toward submitting a complete plan. This approach involves the option that we refer to as an initial submittal, followed by submittal of a complete state plan no later than either June 30, 2017 for single-state plans or June 30, 2018 for multi-state plans.

In addition, for states wishing to participate in a multi-state plan, the EPA is proposing that only one multi-state plan would be submitted on behalf of all participating states, provided it is signed by authorized officials for each of the states participating in the multi-state plan and contains the necessary regulations, laws, etc. for each state in the multi-state plan. In this instance, the joint submittal would have the same legal effect as an individual submittal for each participating state.

2. State Plan Submittal and Timing

The EPA framework regulations (40 CFR 60.23) require that state plans be submitted to the EPA within nine months of promulgation of the emission guidelines, unless the EPA specifies otherwise.[288] In view of the potential that these plans may require states to develop new regulatory or statutory authority, we are proposing that each state must submit a plan to the EPA by June 30, 2016, which is more than one year after the expected finalization date of the emission guidelines. The state may submit a complete plan, or if justified, an initial plan that documents the state's progress in preparing a complete plan. To qualify for an extension of the June 30, 2016 deadline for submitting a complete plan, the state must submit an initial plan that demonstrates the state is on track to develop a complete plan and that includes meaningful steps that clearly commit the state to complete an approvable plan.

The EPA proposes that approvable justifications for seeking an extension beyond 2016 for submitting a complete plan include: A state's required schedule for legislative approval and administrative rulemaking, the need for multi-state coordination in the development of an individual state plan, or the process and coordination necessary to develop a multi-state plan. The EPA is requesting comment on other circumstances for which an extension of time would be appropriate. We are also seeking comment on whether some justifications for extension should not be permissible.

If a state submits an initial state plan by June 30, 2016, and it meets the minimum requirements for an initial state plan, as specified in the plan guidelines, then the deadline extension for submitting a complete plan that the state requested will be deemed granted. If the EPA determines that the initial plan does not meet the guidelines, the EPA will notify the state by letter, within 60 days, that the agency cannot approve the state's initial plan as submitted. The EPA believes this approach is authorized by, and consistent with, section 60.27(a) of the implementing regulations.

If the EPA approves a two-year extension to June 30, 2018, for a state developing a multi-state plan, the state would be required to provide one update, on June 30, 2017, on its progress toward milestones and schedules in the initial plan for developing and submitting a complete plan. We are requesting comment on this approach and the timing and frequency of updates that the state must provide.

3. Components of an Initial State Plan Submittal and Approvability Criteria

As noted, if a state is unable to prepare and submit a complete plan by June 30, 2016, the state must make an initial submittal by that date. To be approved, the EPA proposes that the initial plan must address all components of a complete plan, including identifying which components are not complete. For incomplete components, an approvable initial submittal must contain a comprehensive roadmap outlining the path to completion, including milestones and dates. We recognize that certain options that states may choose involve more analytic effort to precisely demonstrate sources of emission reductions than other options.

The EPA is proposing that the state must provide an opportunity for public comment on a substantial draft of its initial submittal. The EPA proposes that this public comment opportunity will not be governed by the procedural requirements of the framework regulations that apply to the state's adoption of a complete plan, such as the requirement that the state hold a public hearing. 40 CFR 60.23(c)–(f). An initial plan might not include any legally enforceable provisions that the state would have adopted through its administrative or legislative processes, which generally provide for public input. Therefore, to ensure that the public has an opportunity to understand and inform the initial plan, the EPA is proposing that prior to submittal on June 30, 2016 the state must have provided a reasonable opportunity for public comment on a substantial draft of the initial submittal, with notice to the EPA of that comment period. The EPA can use this comment opportunity to advise the state whether it is on track to submit an approvable initial plan. When the state submits its initial plan, it must provide the EPA with a response to any significant comments it received on issues relating to the approvability of the initial plan so that the EPA can fully assess whether it is approvable.

To be approvable, the initial plan must include the following information:

- A description of the plan approach and progress to date in developing a complete plan.
- Initial quantification of the level of emission performance that will be achieved through the plan.
- A commitment to maintain existing measures that limit or avoid CO_2 emissions (e.g., renewable energy

[288] 40 CFR 60.23(a)(1).

standards, unit-specific limits on operation or fuel utilization), at least until the complete plan is approved.

- A comprehensive roadmap for completing the plan, including process, analytical methods, and schedule (with milestones) specifying when all necessary plan components will be complete (e.g., demonstration of projected plan performance; implementing legislation, regulations and agreements; any necessary approvals).
- Identification of existing programs, if any, the state intends to rely on to meet its emission performance level.
- Identification of executed agreements with other states (e.g., memorandum of understanding (MOU)), if a multi-state approach is being pursued.
- A commitment to submit a complete plan by no later than the applicable required date and explanation of actions the state will take to show progress in addressing incomplete plan components.
- A description of all steps the state has already taken in furtherance of actions needed to finalize a complete plan (e.g., copies of draft or proposed regulations, draft or introduced legislation, or draft implementation materials).
- Evidence of an opportunity for public comment and a response to any significant comments received on issues relating to the approvability of the initial plan.

The EPA is soliciting comment on whether there are other elements that a state must include in its initial submittal to qualify for a date extension. Specifically, the EPA requests comment on whether the guidelines should require a state to have taken significant, concrete steps toward adopting a complete plan for the initial plan to be approvable. For example, while it may be difficult for a state to complete its administrative or legislative process within thirteen months, it may be reasonable to require that a state must document that it has at least proposed any necessary regulations and introduced any necessary legislation within the first thirteen months to qualify for additional time to submit a complete plan.

For states participating in a multi-state program, the initial submittal should include executed agreements among the participating states and a road map for both design of the multi-state program and its implementation at the state level. The RGGI provides an example of such an approach. The RGGI participating states signed a Memorandum of Understanding (MOU) in December 20, 2005, in which the states ''express[ed] their mutual understandings and commitments''.[289] The MOU included a detailed outline of the multi-state emission budget trading program, which served as a guide for drafting a model rule. The MOU also included commitments by the participating states to draft and finalize the model rule by specified dates, and a commitment to seek to establish in statute and/or regulation a program materially consistent with the model rule in each state by a specified date.[290] The MOU also included a commitment to launch the program by January 1, 2009 in all states and specified a process for establishing a non-profit organization to assist the states in administering the regional aspects of the program. In addition, prior to execution of the MOU, the RGGI states committed, through letters from the Governors of participating states, to engage in the development of a market-based program to reduce CO_2 emissions from power plants. This was followed by publication of an action plan for tasks leading up to agreement on the basic structure of the program, which was ultimately formalized in the MOU.

4. Process for EPA Review of State Plans

Following the June 30, 2016, deadline for state plan submittals, the EPA will review plan submittals for approvability. For a state that submits an initial state plan by June 30, 2016, and requests an extension of the deadline for the submission of a complete state plan, the EPA will determine if the initial plan submittal meets the minimum requirements for an initial state plan. If it meets the minimum requirements for an initial state plan, as specified in the emission guidelines, the state's request for a deadline extension to submit a complete plan will be deemed granted, and the complete plan must be submitted to the EPA by no later than June 30, 2017 or June 30, 2018 as appropriate.

After receipt of a complete plan submittal, the EPA proposes that the agency will review the plan and, within twelve months, approve or disapprove the plan through a notice-and-comment rulemaking process, similar to that used for approving state implementation plan submittals under section 110 of the CAA. The framework regulations currently provide for the EPA to act on a complete plan within four months. 40 CFR 60.27(b). The EPA proposes that for plans under these guidelines, the agency will act on a complete plan within twelve months to provide adequate time for rulemaking procedures.

Currently, the EPA's framework regulations do not explicitly provide for the EPA to use the different forms of approval actions Congress introduced into the SIP program in the 1990 Clean Air Act Amendments. The EPA is taking comment on whether, for complete state plans under these guidelines, the agency may use two approval mechanisms provided for in CAA sections 110(k)(3) and (4), 42 U.S.C. 7410(k)(3) and (4). CAA section 111(d)(1) provides that the EPA shall establish ''a procedure similar to that provided by section 7410 of this title [section 110 of the Act].'' The EPA is considering whether to update the procedures for acting on complete state plans under the guideline to reflect the enhancements Congress included in CAA section 110 for agency actions on state implementation plans.

The first mechanism is a partial approval/partial disapproval. Where a CAA section 111(d) plan includes severable provisions, some of which are approvable and some of which are not, the EPA is taking comment on whether the agency should interpret the CAA as providing the flexibility to approve those elements that meet the requirements of this guideline, while disapproving those elements that do not. Any plan that is partially approved and partially disapproved would not fully discharge the state's obligation to submit a fully approvable plan, but the partial approval would make federally enforceable those elements of the state's plan that comply with these guidelines.

The second mechanism is a conditional approval. Where a CAA section 111(d) plan is substantially approvable and requires only minor amendments to fully meet the requirements of these guidelines, the EPA is taking comment on whether the agency should interpret the CAA as providing the flexibility to approve that plan on the condition that the state commits to curing the minor deficiencies within one year. Any such conditional approval would be treated as a disapproval if the state fails to comply with its commitment. During the year following the conditional approval while the state works to cure

[289] Regional Greenhouse Gas Initiative Memorandum of Understanding, available at *http://rggi.org/design/history/mou.* Two states subsequently signed the original MOU in early 2007 and a third joined the program later that year through an amendment of the MOU; one of the original states withdrew from the MOU in late 2011.

[290] The model rule specified elements that needed to be consistent across states for the program to function, as well as areas where state rules could differ (e.g., the method used for allocating CO_2 allowances). For more information, see Regional Greenhouse Gas Initiative Model Rule, available at *http://rggi.org/docs/ProgramReview/_FinalProgramReviewMaterials/Model_Rule_FINAL.pdf.*

the deficiency identified in the condition, the state's plan would be federally enforceable.

The EPA has seen that these mechanisms have proven useful when reviewing and acting on state implementation plan submittals under CAA section 110. They allow the state, the EPA, and citizens to enforce good elements of plans or plans that are substantially complete while the state and the EPA work together to put in place a fully approvable plan. The agency notes that complete plan submittals under these guidelines, like SIPs that implement air quality standards, also may contain multiple program elements.

5. Failure To Submit a Complete Plan

If a state fails to submit a complete plan by the applicable deadline, the EPA will notify the state by letter of its failure to submit. The EPA will publish a **Federal Register** notice informing the public of any such notifications. When appropriate, the agency may batch the publication of such notices periodically to simplify publication.

6. Modification of an Approved State Plan

During the course of implementation of an approved state plan, a state may wish to update or alter one or more of the enforceable measures in the state plan, or replace certain existing measures with new measures. The EPA proposes that the state may revise its state plan provided that the revision does not result in reducing the required emission performance for affected EGUs specified in the original approved plan. In other words, no ''backsliding'' on overall plan emission performance through a plan modification would be allowed.

If the state wishes to revise enforceable measures in its approved state plan, the EPA proposes that the state must submit the revised enforceable measures to the EPA and demonstrate that the revised set of enforceable measures in the modified plan will result in emission performance at affected EGUs that is equivalent to or better than the level of emission performance required by the original state plan. In the case of minor changes to enforceable measures, this showing may be a simple explanation of why the changes will not alter the emission performance of affected EGUs under the state plan, or will clearly improve the emission performance of affected EGUs under the state plan. In the case of more substantive changes to enforceable measures, or substitution of a new measure for an old measure, new projections of emission performance under the modified plan would be needed to demonstrate that the modified plan will meet the required level of emission performance for affected EGUs specified in the original approved plan. The EPA requests comment on whether, for such new projections of emission performance, the projection methods, tools, and assumptions used should match those used for the projection in the original demonstration of plan performance, or should be updated to reflect the latest data and assumptions, such as assumptions for current and future economic conditions and technology cost and performance.

7. Plan Templates and Electronic Submittal

The EPA is seeking comment on the creation of a template for initial and complete state plan submittals. A plan template would provide a framework that includes all of the necessary components for an initial and complete submittal that could be populated by states. This could assist states in compiling their plan submittals and streamline EPA review by assuring greater consistency in the format and organization of submittals. This would provide greater certainty for states about what they need to include in a submittal and allow the EPA to provide a quicker response to states about the completeness and approvability of submittals. We are further seeking comment on whether a template may be more appropriate for initial plan submittals than complete plans. Initial plan submittals are likely to be more similar across states, compared to complete plans, which may include a diverse range of components, depending on the state plan approach.

The EPA is also seeking comment on whether it should provide for, or require, electronic submittal of initial and complete plans. It is the EPA's experience that the electronic submittal of information increases the ease and efficiency of data submittal and data accessibility. We note that a number of states have requested an electronic submittal process for state implementation plans (SIPs) under CAA section 110, and the EPA has implemented a pilot program with a number of states for electronic submittal of such plans. The Electronic State Implementation Plan Submission Pilot (eSIPS) includes an EPA-state workgroup that has developed and will evaluate an electronic submission process. This pilot will use the EPA's Central Data Exchange (CDX) electronic submission system. We are seeking comment on the suitability of such an approach for submittal of state plans under CAA section 111(d).

F. State Plan Considerations

The EPA is proposing to give states broad discretion to develop plans that best suit their circumstances and policy objectives. In developing its plan, a state will need to make a number of decisions that will require careful consideration, in order to ensure that its plan both meets the state's policy objectives and is approvable by the EPA. In this section, we identify several key decision points and factors that states should consider when developing their plans.

The EPA has also prepared a TSD, titled ''State Plan Considerations,'' that provides further information on these topics. The agency is seeking comment on the contents of this TSD and all aspects of the state plan decision points and factors below.

1. Affected Entities Other Than Affected EGUs

A state will need to identify each affected entity responsible for meeting compliance obligations under its plan and the means by which compliance with each plan requirement will be met, as well as demonstrate that it has the legal authority to subject such entities to the federally enforceable requirements specified in its state plan. We are proposing that affected entities in an approvable state plan may include: An owner or operator of an affected EGU, other affected entities with responsibilities assigned by a state (e.g., an entity that is regulated by the state, such as an electric distribution utility, or a private or public third-party entity), and a state agency, authority or entity. We are seeking comment on other appropriate examples of affected entities beyond the affected EGUs.

While the EPA seeks to provide states with broad discretion to develop plans that best suit their circumstances and policy objectives, a plan that assigns responsibility to affected entities other than affected EGUs may be more challenging to implement and enforce than a plan with requirements assigned only to affected EGUs.

Furthermore, it may be more challenging for a state to demonstrate that it has sufficient legal authority to subject such affected entities other than affected EGUs to the federally enforceable requirements specified in its state plan. We seek comment on whether the EPA should provide guidance on enforceability considerations related to requirements in a state plan for affected entities other than EGUs (and if so, which such entities). The State Plan Considerations

TSD provides illustrative examples of possible entities and legal mechanisms.

2. Treatment of Existing State Programs

a. Framing Considerations

Many state officials and stakeholders have said that the EPA should avoid structuring the CAA section 111(d) emission guidelines in a way that would disadvantage states that already have adopted programs that reduce CO_2 emissions from EGUs. The EPA agrees with that policy principle.

There is much less agreement among states and stakeholders on the specifics of how existing state programs should be treated in a demonstration that a proposed state plan will achieve the required level of emission performance.

The EPA, starting from recent historical data, has identified the affected EGU emission performance improvements and resulting average emission performance levels for affected EGUs that are achievable, considering cost, in each state over the 2020–2029 period, with achievement of the final CO_2 emission performance level by 2030.

As explained in Section VII above, the EPA's proposed state-specific goals reflect actions that many states have already taken to reduce or avoid EGU CO_2 emissions. CO_2 emission reductions due to shifts to lower CO_2-emitting power generation are also represented in the 2012 base period that was used to assess certain building blocks that are applied in calculating a state emission performance goal.[291]

The agency recognizes that states that have already shifted toward lower carbon-intensity generation or ramped up demand-side EE programs are better positioned to meet state-specific goals. For example, states where significant shifts in generation to NGCC units have already occurred would be closer to the generation mix reflected in the state goals than states where NGCC capacity is not yet being operated to the same degree. Likewise, states with relatively well-established demand-side EE programs would be able to build on those programs more quickly than states with less established programs, and would be closer to, or in some cases already achieving, the level of demand-side energy efficiency reflected in the state goals.

[291] For example, in such instances a significant shift to NGCC generation prior to 2012 may result in a lower potential for further re-dispatch to these units, as witnessed in the 2012 base period data. This would influence the calculated rate-based emission goal for the state, reducing the percentage improvement required relative to the base period CO_2 emission rate.

b. Proposed Approach for Treatment of Existing State Programs and Measures in an Approvable State Plan

The EPA is proposing that existing state programs, requirements, and measures,[292] may qualify for use in demonstrating that a state plan will achieve the required level of emission performance, provided they meet the approvability requirements in the emission guidelines (summarized above in Section VIII.C) and relevant requirements for plan components in the emission guidelines (described above in Section VIII.D). Several options for treatment of existing state programs and measures are described below.

Specifically, the EPA is proposing that, for an existing state requirement, program, or measure, a state may apply toward its required emission performance level the emission reductions that existing state programs and measures achieve during a plan performance period as a result of actions taken after the date of this proposal.[293] This proposed approach would recognize beneficial emission impacts from existing state programs and measures during a plan performance period. It would do so in a way that may be generally compatible with the forward-looking methodology that the EPA used to propose state emission performance goals based on the BSER. By making actions taken after proposal eligible to help meet a state's required emission performance level, this approach would support early beneficial emission-reducing actions. This option would ensure that actions taken after proposal of the emission guidelines and prior to 2020 as a result of requirements in a state plan, could be recognized as contributing toward meeting a state's required emission performance level for affected EGUs.

In general, the agency has identified two broad options for treatment of existing state programs and measures. As noted above, the EPA proposes that emission reductions that existing state requirements, programs and measures achieve during a plan performance period as a result of actions taken after a specified date may be recognized in determining emission performance under a state plan. While proposing that the ''specified date'' would be the date of proposal of these emission guidelines, the EPA also requests comment on the following alternatives: The start date of the initial plan performance period, the date of promulgation of the emission guidelines, the end date of the base period for the EPA's BSER-based goals analysis (e.g., the beginning of 2013 for blocks 1–3 and beginning of 2017 for block 4, end-use energy efficiency), the end of 2005, or another date.

For this option, we are seeking comment on the point in time after which such actions should be able to qualify for use during a plan performance period, considering the method used to set state goals. Whether this option is consistent in practice with the EPA's application of the BSER may depend on the date or dates that are applied for qualifying actions under existing state programs, requirements, and measures. For example, implementation of measures subsequent to the proposal or promulgation of the emission guidelines may be consistent with a forward-looking goal-setting approach, as these actions may be necessary to meet a required level of emission performance during the plan performance period or will put a state in a better position to meet the required level of performance. An example is the EPA's treatment of end-use energy efficiency potential in state goal-setting, where the energy savings achievable during the initial plan performance period are premised in part on a ramping up of end-use energy efficiency programs and cumulative energy savings prior to the beginning of the plan performance period. Earlier dates may also be consistent with a forward-looking goal-setting approach, if the goal-setting approach is premised in part on actions that could be taken prior to the initial plan performance period. However, inconsistency issues may arise if the selected date is not adequately synchronized with the goal-setting method. The EPA requests comment on whether there is a rational basis for choosing a date that predates the base period from which the EPA used historical data to derive state goals. The agency generally requests comment on the appropriate date to select under this option.

The EPA also solicits comment on a second broad option. This option would recognize emission reductions that existing state requirements, programs

[292] An ''existing measure'' refers to a state or utility requirement, program, or measure that is currently ''on the books.'' For the purposes of this discussion, this may include a legal requirement that includes current and future obligations or current programs and measures that are in place and are anticipated to be continued or expanded in the future in accordance with established plans. Existing measures may have past, current, and future impacts on EGU CO_2 emissions.

[293] We are also proposing that this proposed limitation would not apply to existing renewable energy requirements, programs and measures because existing renewable energy generation prior to the date of proposal of the emission guidelines was factored into the state-specific CO_2 goals as part of building block 3.

and measures achieved starting from a specified date prior to the initial plan performance period, as well as emission reductions achieved during a plan performance period. The specified date could be, for example: The date of promulgation of the emission guidelines; the date of proposal of the emission guidelines; the end date of the base period for the EPA's BSER-based goals analysis (e.g., the beginning of 2013 for blocks 1–3 and the beginning of 2017 for block 4, end-use energy efficiency); the end of 2005; or another date.

The EPA requests comment on this option—that emission reduction effects that occur prior to the beginning of the initial plan performance period could be applied toward meeting the required level of emission performance in a state plan. This approach would enable a state to count emission improvements achieved by state programs prior to 2020 toward its interim goal, allowing the state to begin demonstrating emission performance earlier and follow a more gradual emission improvement trajectory during the interim performance period of 2020–2029. This approach would in effect allow higher emissions during the 2020–2029 period than would occur under the proposed approach (i.e., requiring less emission performance improvement during that period). The rationale for this approach would be that higher emissions in 2020–2029 would be offset by pre-2020 emission reductions not required by the CAA section 111(d) program. However, total emissions to the atmosphere would likely be greater under this approach, unless the pre-2020 emission reductions that can be counted toward the state goal are limited to reductions that would not have occurred in the absence of the CAA section 111(d) program. To the extent that states are able to both adopt and implement new requirements earlier than 2020 (e.g., by 2018 or 2019), this approach could provide an incentive for earlier emission reductions. The agency requests comment on whether pre-2020 implementation of new requirements would be practical for states. The agency generally requests comment on this approach, including the conditions that should apply to pre-2020 emission reductions that would count toward the state goal.

The agency also requests comment on the alternative dates listed above in connection with this option. We also request comment on whether this option is inconsistent with the forward-looking method that the EPA has proposed for establishing state goals based on the application of the BSER.

The agency is seeking comment on whether some variation of this approach could be justified as consistent with the EPA's proposed goal-setting approach, as well as the general concept of the BSER and its application in establishing state goals. In particular, we are seeking comment on whether the emission effects of actions that are taken after proposal or promulgation of the emission guidelines or the approval of a state plan, but which occur prior to the beginning of the initial state plan performance period, could be applied toward meeting the required level of emission performance in a state plan.

c. Application of Options Under Rate-Based and Mass-Based Plan Approaches

Under a rate-based approach, the options described above would address the eligibility date for qualifying demand-side EE measures that, through MWh savings, avoid CO_2 emissions from affected EGUs. Measures installed after the eligibility date could generate MWh savings during a plan performance period, and related avoided CO_2 emissions, that could be applied toward meeting a required rate-based emission performance level. Under the proposed option, the eligibility date would be the date of these proposed emission guidelines. For example, under this approach, new demand-side EE measures installed in 2015 or later to meet an existing, on-the-books energy efficiency resource standard (EERS) would be a qualifying measure. However, only MWh savings beginning in 2020 and related avoided CO_2 emissions could be applied toward meeting a required rate-based emission performance level.

Under a mass-based approach, the options described above would be applied when establishing a reference case scenario projection that is used to translate a rate-based goal to a mass-based goal. For example, demand-side EE measures after a respective eligibility date would not be included in the scenario that is used to project CO_2 emissions from affected EGUs when establishing a translated mass-based emission goal. This could be achieved by not including the incremental requirements of an end-use EERS requirement in a reference case projection, beginning at a specified date. These considerations are addressed in more detail in Section VIII.F.7. below and in the Projecting CO_2 Emission Performance in State Plans TSD.

3. Incorporating RE and Demand-Side EE Measures Under a Rate-Based Approach

We are proposing that RE and demand-side EE measures may be incorporated into a rate-based approach through an adjustment or tradable credit system applied to an EGU's reported CO_2 emission rate.[294] Under such a process, measures that avoid EGU CO_2 emissions from affected EGUs, such as quantified and verified end-use energy savings and renewable energy generation, could be credited toward a demonstrated CO_2 emission rate for EGU compliance purposes or used by the state to administratively adjust the average CO_2 emission rate of affected EGUs when demonstrating achievement of the required rate-based emission performance level in a state plan.

Under this approach, affected EGUs[295] could comply with a CO_2 emission rate limit in part through the use of credits for actions that avoid CO_2 emissions from affected EGUs. If a state is implementing a portfolio approach, then the state could administratively adjust the average CO_2 emission rate of affected EGUs through a similar process, provided that the CO_2-avoiding measures are enforceable elements of the state plan.

We are seeking comment on different approaches for providing such crediting or administrative adjustment of EGU CO_2 emission rates, which are elaborated further in the State Plan Considerations TSD.

Credits or adjustment might represent avoided MWh of electric generation or avoided tons of CO_2 emissions. The approach chosen could have significant implications for the amount of adjustment or credit provided for RE and demand-side EE measures. If adjustment or credits represent avoided MWh, they would be added to the denominator when determining an adjusted lb CO_2/MWh emission rate. If adjustment or credits represent avoided CO_2 emissions, they would be subtracted from the numerator when determining an adjusted lb CO_2/MWh emission rate.

A MWh crediting or adjustment approach implicitly assumes that the avoided CO_2 emissions come directly from the particular affected EGU (or group of EGUs) to which the credits are

[294] We are also proposing that RE and demand-side EE measures could be used under a mass-based portfolio approach in an approvable state plan. However, the focus of this section is limited to application of such measures under a rate-based approach.

[295] This could include an individual affected EGU or group of affected EGUs if a rate-based averaging or trading approach is used.

applied. It assumes, in effect, that an additional emission-free MWh is being generated by that respective EGU, and that the RE or demand-side EE measure reduces CO_2 emissions from that individual EGU or group of EGUs.[296] In practice, the average or marginal CO_2 emission rate in the power pool or identified region—representing the avoided CO_2 emissions from the generating sources being displaced by a MWh of energy savings or a MWh of renewable energy generation—could differ significantly from the calculated avoided CO_2 emissions derived by adjusting the MWh output of an affected EGU.

An alternative approach is to provide an adjustment based on the estimated CO_2 emissions that are avoided from the power pool or identified region as a result of RE and demand-side EE measures. This approach implicitly assumes that the avoided CO_2 emissions come from the electric power pool or other identified region as a whole, rather than an individual EGU. The avoided CO_2 emissions are determined based on the MWh saved or generated, multiplied by a CO_2 emission rate for the power pool or region. This CO_2 emission rate could be based on the average or marginal emission rate in the power pool or region, or could be based on the emission rate that represents the required rate-based emission performance level in the plan. We invite comment on each of these possible approaches.

In addition, because some of the CO_2 emissions avoided through RE and demand-side EE measures may be from non-affected EGUs, we are seeking comment on how this might be addressed in a state plan, whether when adjusting or crediting CO_2 emission rates of affected EGUs based on the effects of RE and demand-side EE measures or otherwise. How these dynamics might be addressed, both in projections of plan performance and in actual demonstration of performance achieved under a plan, is further discussed in the State Plan Considerations TSD.

4. Quantification, Monitoring, and Verification of RE and Demand-Side EE Measures

A key consideration for state plans is the process and requirements under a state plan for quantifying, monitoring, and verifying the effect of RE and demand-side EE measures that result in electricity generation or electricity savings.

The EPA is proposing that a state plan that includes enforceable RE and demand-side EE measures must include an evaluation, measurement, and verification (EM&V) plan that explains how the effect of these measures will be determined in the course of plan implementation. An EM&V plan will specify the analytic methods, assumptions, and data sources that the state will employ during the state plan performance periods to determine the energy savings and energy generation related to RE and demand-side EE measures. An EM&V plan would be subject to EPA approval as part of a state plan. As discussed below, the EPA intends to develop guidance on acceptable EM&V methods that could be incorporated in an approvable EM&V plan that is included as part of an approvable state plan.

Utilities and states have conducted ongoing EM&V of demand-side EE and RE measures and programs for several decades. Current practice with EM&V for RE and demand-side EE programs in the U.S. is primarily defined by state public utility commission (PUC) requirements for customer-funded energy efficiency and renewable energy programs, as well as related compliance and reporting requirements for EERS and renewable portfolio standards (RPS).

The level of PUC oversight of demand-side EE programs varies from state to state, but this oversight process has generated the majority of the industry guidance and protocols for documenting energy savings from EE programs. Typically, impact evaluation reports are responsive to requirements established by PUCs and submitted (usually annually) for PUC review, approval, and use in resource planning and performance assessment. These PUC requirements generally rely upon a well-defined set of industry-standard practices and procedures. In states with the most experience implementing and overseeing demand-side EE programs, this typically includes: Use of one or more industry-standard EM&V protocols or guidelines; use of ''deemed savings values,'' [297] where appropriate, for well-understood demand-side EE measures; consideration of local factors, such as climate, building type, and occupancy; involvement of stakeholders and solicitation of expert advice regarding EM&V processes and resulting energy savings impacts; conduct of EM&V activities (e.g., direct equipment measurements, application of deemed savings, and reporting of impacts) on a regular basis; and provision of interim and annual reporting of achieved energy savings.

Despite this well-defined and generally accepted set of industry practices, many states with energy efficiency programs use different input values and assumptions in applying these practices (e.g., net versus gross savings,[298] run-time of equipment, measure lifetime). This can result in significant differences in claimed energy savings values for similar energy efficiency measures between states and utilities, even when the same measure type is installed under otherwise identical circumstances. In response to a growing awareness of this lack of cross-state comparability, policy makers, regulatory agencies, and other stakeholders are increasingly advocating for the use of common evaluation approaches across jurisdictions. A number of states and utilities in different regions of the country are already working to develop such common approaches.

For RE measures and programs, EM&V employed by states and utilities commonly relies upon a set of standard practices and procedures, such as the use of revenue-quality meters for quantifying RE generation. As a result, existing state and utility requirements and processes for quantification, monitoring, and verification of RE programs and measures generally provide a solid foundation for minimum requirements or guidance established by the EPA for state plans.

For both RE and demand-side EE measures included in state plans, additional information and reporting may be necessary to accurately quantify the avoided CO_2 emissions associated with these measures, such as information on the location and the hourly, daily, or seasonal basis of renewable energy generation or energy savings.

Current state and utility EM&V approaches for RE and demand-side EE programs and mandates are discussed in more detail in the State Plan

[296] As a result, the assumed avoided CO_2 emissions from an individual MWh of energy savings or MWh of generation from renewable energy will differ based on the reported CO_2 emission rate of the individual EGU to which the MWh is applied as an adjustment to its MWh output.

[297] Deemed savings are measure-specific stipulated values based on historical and verified data. Unlike other EM&V approaches, deemed savings approaches involve limited or no measurement activities, and are therefore a common and relatively low-cost strategy for documenting energy savings.

[298] Gross savings are the change in energy use (MWh) and demand (MW) that results directly from program-related actions taken by program participants, regardless of why they participated in a program. Net savings refer to the change in energy use and demand that is directly attributable to a particular energy efficiency program.

Considerations TSD. We are seeking comment on the suitability of these approaches in the context of an approvable state plan, and on whether harmonization of state approaches, or supplemental actions and procedures, should be required in an approvable state plan. In particular, we intend to establish guidance for acceptable quantification, monitoring, and verification of RE and demand-side EE measures for an approvable EM&V plan, and are seeking comment on critical features of such guidance, including scope, applicability, and minimum criteria.[299] We are also seeking comment on the appropriate basis for and technical resources used to establish such guidance, including consideration of existing state and utility protocols, as well as existing international, national, and regional consensus standards or protocols.[300] The EPA's goal in developing such guidance is to assure that it is consistent with industry-standard EM&V approaches for both RE and demand-side EE measures and programs, leverages the EM&V resources and infrastructure already in place in many states, and strikes a reasonable balance between EM&V costs, rigor, and the value of resulting information, while considering the specific use of such information in assessing avoided CO_2 emissions from affected EGUs.

In developing guidance, the agency does not intend to limit the types of RE and demand-side EE measures and programs that can be included in a state plan, provided that supporting EM&V is rigorous, complete, and consistent with the EPA's guidance. This approach recognizes differences among RE and demand-side EE programs and measures with respect to implementation history and experience, existence of applicable EM&V protocols and methods, and the nature and type of program oversight (e.g., whether or not a program is subject to PUC oversight). The EPA is requesting comment on the merits of this approach, including whether such guidance should identify types of RE and demand-side EE measures and programs for which evaluation of results is relatively straightforward and which are appropriate for inclusion in a state plan. Such approaches might be subject to streamlined review of EM&V protocols included in an approvable state plan, provided that such protocols are applied in accordance with industry best practices. For example, many utilities have implemented a similar core set of RE and demand-side EE measures and programs for utility customers. For these types of measures and programs, a substantial base of experience has been established nationally for the evaluation of measure and program outcomes. Other types of measures and programs, such as those that seek to alter consumer and building occupant behavior might pose quantification and verification challenges. Still other types of measures, such as state energy-efficient appliance standards and building codes, have not typically been subject to similar evaluation of energy savings results. These types of approaches might have substantial impacts, and the EPA does not want to discourage their implementation in state plans, but they might require development of appropriate quantification, monitoring, and verification protocols. The EPA and its federal partners intend to discuss the development of appropriate EM&V protocols for such measures with states in the coming years.

As an alternative to the EPA's proposed approach of allowing a broad range of RE and demand-side EE measures and programs to be included in state plans, provided that supporting EM&V documentation meets applicable minimum requirements, the EPA is requesting comment on whether guidance should limit consideration to certain well-established programs, such as those characterized in Section V.A.4.2.1 of the State Plan Considerations TSD.

5. Reporting and Recordkeeping for Affected Entities Implementing RE and Demand-Side EE Measures

If a state plan incorporates RE and demand-side EE measures under a rate-based approach or implements a mass-based portfolio approach with such measures, reporting and recordkeeping requirements for an approvable plan would differ from those applicable to an affected EGU. For example, these requirements may include compliance reporting by an electric distribution utility subject to an EERS or RPS. They may also include reporting by a vertically integrated utility implementing an approved integrated resource plan. In the latter instance, the utility might also be the owner and operator of affected EGUs, but additional reporting of quantified effects of RE and demand-side EE measures under the utility plan would be necessary to demonstrate emission performance under the state plan. In other instances, a state agency or entity or a private or public third-party entity might be implementing programs and measures that support the deployment of end-use energy efficiency and clean energy technologies that are incorporated into a state plan. In each of these instances, reporting of program compliance or program outcomes is a necessary part of an approvable plan to demonstrate emission performance under the plan.

Examples of potential reporting obligations for affected entities implementing RE and demand-side EE measures in an approvable state plan are provided in the State Plan Considerations TSD. We are seeking comment on the examples and suitability of potential approaches described in the TSD and any other appropriate reporting and recordkeeping requirements for affected entities beyond affected EGUs.

6. Treatment of Interstate Effects

The electricity system and wholesale electricity markets are interstate in nature. EGUs in one state provide electricity to customers in neighboring states. Power companies often own EGUs in more than one state and manage them as a system. EGUs are dispatched both within and across state borders.

Similarly, programs and measures in a state plan, such as RE and demand-side EE measures, may affect the performance of the interconnected electricity system beyond a state border. In addition, many state programs allow for actions in neighboring states to meet the in-state requirement or explicitly address CO_2 emissions in neighboring states. For example, many state renewable portfolio standards allow for generation by qualifying renewable energy sources in other states to count toward meeting the state portfolio requirement. Some states also apply CO_2 emission requirements related to the generation of power purchased by regulated utilities, including power imported from out of state.

The EPA recognizes the complexity of accounting for interstate effects associated with measures in a state plan in a consistent manner, to allow states to take into account the CO_2 emission reductions resulting from these programs while minimizing the likelihood of double counting. We also realize that interstate effects on CO_2 emissions from affected EGUs could be attributed in different manners in the context of an approvable state plan. The EPA is seeking comment on the options summarized below, as well as alternatives. These options and alternatives, and how they might apply to both projections of plan performance

[299] Section V.A.4 of the State Plan Considerations TSD includes a detailed description of these EM&V parameters.

[300] A list of these protocols is provided in Section V.A.3.1 of the State Plan Considerations TSD.

and reporting of achieved plan performance, are addressed in the State Plan Considerations TSD.

The EPA is proposing that, for demand-side EE measures, consistent with the approach that the EPA used in determining the BSER, a state could take into account in its plan only those CO_2 emission reductions occurring (or projected to occur) in the state that result from demand-side EE measures implemented in the state. The agency is also proposing that, for states that participate in multi-state plans, the participating states would have the flexibility to distribute the CO_2 emission reductions among states in the multi-state area, as long as the total CO_2 emission reductions claimed are equal to the total of each state's in-state emissions reductions that result from demand-side EE measures implemented in those states. We are also proposing that states could jointly demonstrate CO_2 emission performance by affected EGUs through a multi-state plan in a contiguous electric grid region, in which case attribution of emission reductions from demand-side EE measures would not be necessary. We also request comment on whether a state should be able to take credit for emission reductions out of state due to in-state EE measures if the state can demonstrate that the reductions will not be double-counted when the relevant states report on their achieved plan performance, and what such a demonstration should entail. We request comment on these and other approaches for taking into account CO_2 emission reductions from demand-side EE measures in state plans.

The EPA is proposing that, for renewable energy measures, consistent with existing state RPS policies, a state could take into account all of the CO_2 emission reductions from renewable energy measures implemented by the state, whether they occur in the state or in other states. This proposed approach for RE acknowledges the existence of renewable energy certificates (REC) that allow for interstate trading of RE attributes and the fact that a given state's RPS requirements often allow for the use of qualifying RE located in another state to be used to comply with that state's RPS.

The EPA is also seeking comment on how to avoid double counting emission reductions using this proposed approach. The agency is also proposing that states participating in multi-state plans could distribute the CO_2 emission reductions among states in the multi-state area, as long as the total CO_2 emission reductions claimed are equal to the total of each state's in-state emission reductions from RE measures. We also request comment on the option of allowing a state to take into account only those CO_2 emission reductions occurring in its state. We are also proposing that states could jointly demonstrate CO_2 emission performance by affected EGUs through a multi-state plan in a contiguous electric grid region, in which case attribution among states of emission reductions from renewable energy measures would not be necessary. We also request comment on whether a state should be able to take credit for emission reductions out of state due to renewable energy measures if the state can demonstrate that the reductions will not be double-counted when the relevant states report on their achieved plan performance, and on what such a demonstration should entail. We request comment on these and other approaches for taking into account CO_2 emission reductions from renewable energy measures.

7. Projecting Emission Performance

As proposed, an approvable state plan will include a projection of CO_2 emission performance by affected EGUs under the plan. In addition, a state plan that is using a mass-based goal in determining the required level of emission performance under the plan will include a translation of the rate-based emission goal in the emission guidelines to a mass-based goal. This translation will involve a projection of CO_2 emissions from affected EGUs during the initial 2020–2029 plan performance period and in 2030, under a scenario that assumes the rate-based goal in the emission guidelines is met.

The EPA is striving to find a balance between providing state implementation flexibility and ensuring that the emission performance required by CAA section 111(d) is properly defined in state plans and that plan performance projections have technical integrity. Each state plan must include a projection of CO_2 emission performance from affected EGUs during the multi-year plan period that will result from implementation of the plan. Depending on the type of plan approach, this will include either a projection of the average CO_2 emission rate achieved by affected EGUs or total CO_2 emissions from affected EGUs.

The credibility of state plans under CAA section 111(d) will depend in large part on ensuring credible and consistent emission performance projections in state plans. Therefore, the use of appropriate methods, tools and assumptions for such projections is critical.

Considerations for projecting emission performance under a state plan will differ depending on the type of plan. This includes differences in how inputs to projections are derived; how projections are conducted, including tools, methods and assumptions; and how aspects of a plan are represented in these projections.

In general, any material component of a state requirement or program included in a state plan that could affect emission performance by affected EGUs should be accurately represented in emission projections included in the state plan.

For example, mass-based emission budget trading programs include a number of compliance flexibility mechanisms that might impact emission performance achieved by affected EGUs subject to these programs. These include multi-year compliance periods; the ability to bank allowances issued in a previous compliance period for use in a subsequent compliance period; the use of out-of-sector project-based emission offsets; and cost-containment allowance reserves that make additional allowances available to the market if pre-established allowance price thresholds are achieved. As a result, annual emissions from affected sources subject to an emission budget trading program often differ from the established annual emission budget for affected sources. In addition, these programs may be multi-sector in nature, regulating emissions for source categories in addition to EGUs. As a result, emission projections in state plans will need to accurately account for and represent these compliance flexibilities, as well as the scope of affected sources if they are broader than EGUs affected under CAA section 111(d). Similarly, other types of state programs, such as RPS, may include flexibility mechanisms or other provisions, such as alternative compliance payment mechanisms, banking, and limits on total ratepayer impact, that affect the ultimate amount of electricity generation required under the portfolio standard. These considerations for different types of state programs are discussed in more detail in the Projecting EGU CO_2 Emission Performance in State Plans TSD.

In general, as with projections used to determine a mass-based goal, projections of emission performance under a state plan could be conducted using historical data and parameters for estimating the future impact of individual state programs and measures. Alternatively, a projection could include modeling, such as use of a capacity planning and dispatch model.[301] This latter approach would be able to capture dynamic interactions within the electricity sector, based on system operation and market forces, including interactions among state programs and measures and the dynamics of market-based measures.

These considerations, and considerations for projecting emission performance under different types of state plan approaches, are discussed in detail in the Projecting EGU CO_2 Emission Performance in State Plans TSD.

We are seeking comment on the considerations discussed in this TSD, including options presented for how projections might be conducted in an approvable state plan, and how different types of state plan approaches are represented in these projections. We are seeking further comment on whether the EPA should develop guidance that describes acceptable projection approaches, tools, and methods for use in an approvable plan, as well as providing technical resources for conducting projections.

The ISO/RTO Council, an organization of electric grid operators, has suggested that ISOs and RTOs could provide analytic support to help states develop and implement their plans. The ISOs and RTOs have the capability to model the system-wide effects of individual state plans. Providing assistance in this way, they felt, would allow states with borders that fall within an ISO or RTO footprint to assess the system-wide impacts of potential state plan approaches. In addition, as the state implements its plan, ISO/RTO analytic support would allow the state to monitor the effects of its plan on the regional electricity system. ISO/RTO analytic capability could help states assure that their plans are consistent with region-wide system reliability. The ISO/RTO Council suggested that the EPA ask states to consult with the applicable ISO/RTO in developing their state plans. The EPA agrees with this suggestion and encourages states with borders that fall within one or more ISO or RTO footprints to consult with the relevant ISOs/RTOs.

8. Potential Emission Reduction Measures Not Used To Set Proposed Goals

States may include measures in their plans beyond those that the EPA included in its determination of the BSER. In general, any measures that meet the proposed criteria for approvable state plans could be employed in a state plan. Beyond that, under a mass-based approach, any measure that reduces affected EGU emissions—even if not included in the state plan—will, if implemented during a plan performance period, help to achieve actual emissions performance that meets the required level.

Beyond the types of state plan measures already discussed in this section of the preamble, the agency has identified a number of other measures that could also lead to CO_2 emission reductions from EGUs. These include, for example, electricity transmission and distribution efficiency improvements, retrofitting affected EGUs with partial CCS, the use of biomass-derived fuels at affected EGUs, and use of new NGCC units. Although the emission reduction methods discussed in this section are not proposed to be part of the BSER, the agency anticipates that some states may be interested in using these approaches in their state plans. The agency solicits comment on whether these measures are appropriate to include in a state plan to achieve CO_2 emission reductions from affected EGUs. In addition to the specific requests for comment related to specific technologies below, we also request comment on other measures that would be appropriate. In addition, we request comment on whether the EPA should provide specific guidance on inclusion of these measures in a state plan.

In addition, technological advances and innovations in energy and pollution control technologies will continue over time. The agency is aware that as new technologies become available or as costs of a technology drop because of technical advances, states may wish to include measures in their state plans that make use of those technologies.

To be more specific, there are multiple potential measures that can be taken at an EGU beyond heat rate improvements that will reduce CO_2 emissions. Some examples are: Including co-firing of less CO_2 intensive fuels such as natural gas, retrofit of partial CCS and use of integrated renewable technology (i.e. meeting some of the steam load in a steam turbine from a fossil unit and part of the steam load from a concentrating solar installation), and improving heat rates of oil- and gas-fired generating units. Co-firing of natural gas and the use of CCS could be incorporated into a state plan demonstration of emission performance as a reduction in the emission rate at an affected EGU in exactly the same way that heat rate reductions could be quantified. In the case of an integrated renewable and fossil unit, reductions could either be quantified as a reduction in rate, or the renewable component could be quantified in the same way other renewable reductions are quantified in the state plan.

In addition to the nuclear generation taken into account in the state goals analysis, any additional new nuclear generating units or uprating of existing nuclear units, relative to a baseline of capacity as of the date of proposal of the emission guidelines, could be a component of state plans. This baseline would be consistent with the proposed approach for treatment of existing state programs. The agency requests comment on alternative nuclear capacity baselines, including whether the date for recognizing additional non-BSER nuclear capacity should be the end of the base year used in the BSER analysis of potential nuclear capacity (i.e., 2012). In general, when considering nuclear generation in a state plan, states may wish to consider the impacts that different types of policies may have on different types of zero-emitting generation. Under a capped approach which does not provide any ''crediting'' for zero-emitting generation, the impact on all zero-emitting units should be the same. In a rate based approach that credited zero or low-emitting generation, the crediting mechanism used could result in different economic impacts on different types of zero- or low-emitting generation.

Another way that a state plan could reduce utilization and emissions from affected existing EGUs would be through construction of new NGCC—that is, NGCC on which construction commences after the date of proposal or finalization of CAA section 111(b) standards applicable to that source. (The agency's CAA section 111(d) proposal does not include new NGCC as a component of the BSER, but requests comment on that question in Section VI of this preamble.) Under a mass-based plan where an emission limit on affected EGUs would assure achievement of the required level of emission performance in the state plan, any emission reductions at affected EGUs resulting from substitution of new NGCC generation for higher-emitting generation by existing affected EGUs would automatically be reflected in mass emission reductions from affected EGUs. A state would not need to include enforceable provisions for new NGCC in its plan, under such an approach. However, under a mass-based portfolio approach, enforceable measures in a state plan might include

[301] In many cases, this approach will also require the development of parameters for estimating the future effect of individual state programs and measures, for use as input assumptions for modeling.

construction of new NGCC to replace one or more affected EGUs, perhaps as part of a utility IRP and related PUC orders. Again, the effects of new NGCC generation would be realized in reduced mass emissions from affected EGUs.

The agency requests comment on how emissions changes under a rate-based plan resulting from substitution of generation by new NGCC for generation by affected EGUs should be calculated toward a required emission performance level for affected EGUs. Specifically, considering the legal structure of CAA section 111(d), should the calculation consider only the emission reductions at affected EGUs, or should the calculation also consider the new emissions added by the new NGCC unit, which is not an affected unit under section 111(d)? Should the emissions from a new NGCC included as an enforceable measure in a mass-based state plan (e.g., in a plan using a portfolio approach) also be considered?

Similar to zero-emitting generation, states may also want to consider whether the policy design they choose sends similar or different price signals to new and existing NGCC. For instance, under a mass based program, if new NGCCs were not included, their costs would be less than the cost of an existing NGCC unit.

In respect to new fossil fuel-fired EGUs, the agency also requests comment on the concept of providing credit toward a state's required CAA section 111(d) performance level for emission performance at new CAA section 111(b) affected units that, through application of CCS, is superior to the proposed standards of performance for new EGUs. Because the EPA proposed to find that the BSER for new fossil fuel-fired boilers and IGCC units is only a partial application of CCS, we recognize that there is the potential for such units, if constructed, to obtain additional emission reductions by increasing the level of CCS and outperforming the proposed performance standards. In some cases these incremental emission reductions may represent a cost effective abatement option for states and would provide an incentive for the deployment and advancement of CCS. We invite comment on whether incremental emission reductions from new fossil fuel-fired boilers and IGCC units with CCS, based on exceeding the CAA section 111(b) performance standards for such units, should be allowed as a compliance option to help meet the emission performance level required under a CAA section 111(d) state plan.

Similarly, while the EPA did not propose to establish standards of performance for new NGCC units based on CCS under CAA section 111(b), we recognize that if a new NGCC unit were to be constructed with a CCS system, it could achieve a lower CO_2 emission rate than required by the proposed standards of performance for new NGCC units. We invite comment on whether incremental emission reductions from new NGCC units that outperform the performance standards for such units under CAA section 111(b) based on the use of CCS should be allowed as a compliance option to help meet the emission performance level required under a CAA section 111(d) state plan.

Building block 4 focuses on improving end-use energy efficiency. Another way to reduce the utilization of, and CO_2 emissions from, affected EGUs is through electricity transmission and distribution upgrades that reduce electricity losses during the delivery of electricity to end users. Just as end-use energy efficiency can reduce mass emissions from affected EGUs, so can transmission upgrades.

In addition, electricity storage technologies have the potential to enhance emission performance by reducing the need for fossil fuel-fired EGUs to provide generation during periods when intermittent wind and solar generation are unavailable due to natural conditions. States may wish to consider this possibility as they consider options for design of their plans.

The agency requests comment on whether industrial combined heat and power approaches warrant consideration as a potential way to avoid affected EGU emissions, and whether the answer depends on circumstances that depend on the type of CHP in question.

Many of the decisions that states will make while developing compliance approaches are fundamentally state decisions that will have impacts on issues important to the state, including cost to consumers and broader energy policy goals, but will not impact overall emission performance. Some decisions, however, may impact emission performance and exemplify the kinds of decisions and approaches states may be interested in pursuing. In light of the broad latitude that the EPA is seeking to afford the states, including latitude to adopt measures such as those discussed in this subsection, the EPA intends to make additional technical resources available and consider developing guidance for states, should they need such support in exploring and adopting these options. The EPA, in addition, requests comment on whether there are still other areas beyond those discussed above for which it would be useful for the EPA to provide guidance.

Through President Obama's Climate Action Plan, the Administration is working to identify new approaches to protect and restore our forests, as well as other critical landscapes including grasslands and wetlands, in the face of a changing climate. Sustainable forestry and agriculture can improve resiliency to climate change, be part of a national strategy to reduce dependence on fossil fuels, and contribute to climate change mitigation by acting as a ''sink'' for carbon. The plant growth associated with producing many of the biomass-derived fuels can, to varying degrees for different biomass feedstocks, sequester carbon from the atmosphere. For example, America's forests currently play a critical role in addressing carbon pollution, removing nearly 12 percent of total U.S. greenhouse gas emissions each year. As a result, broadly speaking, burning biomass-derived fuels for energy recovery can yield climate benefits as compared to burning conventional fossil fuels.

Many states have recognized the importance of forests and other lands for climate resilience and mitigation and have developed a variety of different sustainable forestry policies, renewable energy incentives and standards and greenhouse gas accounting procedures. Because of the positive attributes of certain biomass-derived fuels, the EPA also recognizes that biomass-derived fuels can play an important role in CO_2 emission reduction strategies. We anticipate that states likely will consider biomass-derived fuels in energy production as a way to mitigate the CO_2 emissions attributed to the energy sector and include them as part of their plans to meet the emission reduction requirements of this rule, and we think it is important to define a clear path for states to do so.

To better understand the impacts of using different types of biomass-derived fuels, the EPA is assessing the use of biomass feedstocks for energy recovery by stationary sources and has developed a draft accounting framework that the EPA's Science Advisory Board (SAB) has reviewed. The draft framework concluded that while biomass and other biogenic feedstocks have the potential to reduce the overall level of CO_2 emissions resulting from electricity generation, the contribution of biomass-derived fuels to atmospheric CO_2 is sensitive to the type of biomass feedstock used, and the way in which the feedstock is grown, processed, and ultimately combusted as a fuel for energy production. The SAB in its review similarly found that there are circumstances in which biomass is grown, harvested and combusted in a carbon neutral fashion but commented that additional considerations are warranted.

The EPA is in the process of revising the draft framework and considering next steps, taking into account both the comments provided by the SAB and feedback from stakeholders. The EPA's biogenic CO_2 accounting framework is expected to provide important information regarding the scientific basis for assessing these biomass-derived fuels and their net atmospheric contribution of CO_2 related to the growth, harvest and use of these fuels. This information should assist both states and the EPA in assessing the impact of the use of biomass fuels in reaching emission reduction goals in the energy sector under state plans to comply with the requirements in the emission guidelines.

9. Consideration of a Facility's ''Remaining Useful Life'' in Applying Standards of Performance

In this section, the EPA discusses the relevance to this rule of the EPA regulations implementing the CAA section 111(d)(1) provision ''permit[ing] the State in applying a standard of performance to any particular source under a [111(d)] plan . . . to take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies.''

For the reasons discussed below, the EPA is proposing that, in this case, the flexibility provided in the state plan development process adequately allows for consideration of the remaining useful life of the affected facilities and other source-specific factors and, therefore, that separate application of the remaining useful life provision by states in the course of developing and implementing their CAA section 111(d) plans is unnecessary. The agency is requesting comment on its analysis below of the implications of the EPA's existing regulations interpreting ''useful life'' and ''other factors'' for purposes of this rulemaking.[302] The agency also requests comment on whether it would be desirable to include in regulatory text any aspects of this preamble discussion about how the provisions in the existing implementing regulations concerning source-specific factors relate to this emission guideline.

This section addresses the legal background concerning facility-specific considerations and the implications for implementation of these emission guidelines, including state emissions performance goals.

a. Legal Background

The EPA's 1975 implementing regulations[303] address remaining useful life and other facility-specific factors that might affect requirements for an existing source under section 111(d). Those regulations provide that for a pollutant such as GHGs, which have been found to endanger public health, standards of performance in state plans must be as stringent as the EPA's emission guidelines. Deviation from the standard might be appropriate where the state demonstrates with respect to a specific facility (or class of facilities):

(1) Unreasonable cost of control resulting from plant age, location, or basic process design;

(2) Physical impossibility of installing necessary control equipment; or

(3) Other factors specific to the facility (or class of facilities) that make application of a less stringent standard or final compliance time significantly more reasonable.

The reference to ''[u]nreasonable cost of control resulting from plant age'' implements the statutory provision on remaining useful life. The language concerning plant location, basic process design, physical impossibility of installing controls, and ''other factors'' addresses facility-specific issues other than remaining useful life that the EPA determined that in some circumstances can affect the reasonableness of a control measure for a particular existing source.

This regulatory provision provides the EPA's default structure for implementing the remaining useful life provision of CAA section 111(d). The opening clause, however, which provides that this provision is applicable ''unless otherwise specified in the applicable subpart'' makes clear that this structure may not be appropriate in each case and that the EPA has discretion to alter the extent to which states may authorize relaxations to standards of performance that would otherwise apply to a particular source or source category, if appropriate under the circumstances of the specific source category and proposed guidelines.

b. Implications for Implementation of These Emission Guidelines

In general, the EPA notes that the implementing regulation provisions for remaining useful life and other facility-specific factors are relevant for emission guidelines in which the EPA specifies a presumptive standard of performance that must be fully and directly implemented by each individual existing source within a specified source category. Such guidelines are much more like a CAA section 111(b) standard in their form. For example, the EPA emission guidelines for sulfuric acid plants, phosphate fertilizer plants, primary aluminum plants, and Kraft pulp plants specify emission limits for sources.[304] In the case of such emission guidelines, some individual sources, by virtue of their age or other unique circumstances, may warrant special accommodation.

In these proposed guidelines for state plans to limit CO_2 from affected EGUs, the agency does not take that approach. Instead, the EPA is proposing to establish state emission performance goals for the collective group of affected EGUs in a state, leaving to each state the design of the specific requirements that fall on each affected EGU. Due to the inherent flexibility in the EPA's approach to establishing the state-specific goals, and the flexibility provided to states in developing approvable CAA section 111(d) plans to achieve those goals, the EPA's guidelines contain no emission standards that the state must apply directly to a specific EGU; therefore, no relief for individual facilities would be needed.

Rather, because of the flexibility for states to design their own standards, the states have the ability to address the issues involved with ''remaining useful life'' and ''other factors'' in the initial design of those standards, which would occur within the framework of the CAA section 111(d) plan development process. States are free to specify requirements for individual EGUs that are appropriate considering remaining useful life and other facility-specific factors.

Therefore, to the extent that a performance standard that a state may wish to adopt for affected EGUs raises facility-specific issues, the state is free to make adjustments to a particular facility's requirements on facility-specific grounds, so long as any such adjustments are reflected (along with

[302] The agency is not reopening or considering changes to this provision of the implementing regulations.

[303] 40 CFR 60.24(f).

[304] *See* ''Phosphate Fertilizer Plants; Final Guideline Document Availability,'' 42 FR 12,022 (Mar. 1, 1977); ''Standards of Performance for New Stationary Sources; Emission Guideline for Sulfuric Acid Mist,'' 42 FR 55,796 (Oct. 18, 1977); ''Kraft Pulp Mills, Notice of Availability of Final Guideline Document,'' 44 FR 29,828 (May 22, 1979); ''Primary Aluminum Plants; Availability of Final Guideline Document,'' 45 FR 26,294 (Apr. 17, 1980); ''Standards of Performance for New Stationary Sources and Guidelines for Control of Existing Sources: Municipal Solid Waste Landfills, Final Rule,'' 61 FR 9905 (Mar. 12, 1996).

any necessary compensating emission reductions), as part of the state's CAA section 111(d) plan submission. The agency requests comment on its interpretation.

c. Relationship to State Emission Performance Goals and Timing of Achievement

The EPA also believes that, because of the way the state-specific goals have been developed in these proposed guidelines, remaining useful life and other facility-specific considerations should not affect the determination of a state's rate-based or mass-based emission performance goal or the state's obligation to develop and submit an approvable CAA section 111(d) plan that achieves that goal by the applicable deadline.

Under the proposed guideline, states would have the flexibility to adopt a state plan that relies on emission-reducing requirements that do not require affected EGUs with a short remaining useful life to make major capital expenditures [305] or incur unreasonable costs. Indeed, the EPA's proposal would provide states with broad flexibility regarding ways to improve emission performance through utilizing the emissions reduction methods represented by the four ''building blocks.''

We also note that a state is not required to achieve the same level of emission reductions with respect to any one building block as assumed in the EPA's BSER analysis. If a state prefers not to attempt to achieve the level of performance estimated by the EPA for a particular building block, it can compensate through over-achievement in another one, or employ other compliance approaches not factored into the state-specific goal at all. The EPA has estimated reasonable rather than maximum possible implementation levels for each building block in order to establish overall state goals that are achievable/while allowing states to take advantage of the flexibility to pursue some building blocks more aggressively, and others less aggressively, than is reflected in the goal computations, according to each state's needs and preferences.

Of the four building blocks considered by the EPA in developing state goals, only the first block, heat rate improvements, involves capital investments at the affected EGUs which, if mandated by a state rule, might give rise to remaining useful life considerations at a particular facility. The other building blocks—re-dispatch among affected sources, addition of new generating capacity, and improvement in end-use energy efficiency—do not generally involve capital investments by the owner/operator at an affected EGU.

In the case of heat rate improvements at affected EGUs, states can choose whether to require a greater or lesser degree of heat rate improvement than the 6 percent improvement assumed in the EPA's proposed BSER determination, either because of the remaining useful life of one or more EGUs, other source-specific factors that the state deemed appropriate to consider, or any other relevant reasons. The agency also notes that any capital expenditures would be much smaller than capital expenditures required for example, for purchase and installation of scrubbers to remove sulfur dioxide; a fleet-wide average cost for heat rate improvements at coal-fired generating units is $100/kW, compared with a typical SO_2 scrubber cost of $500/kw (costs vary with unit size).[306] In addition, the proposed guideline allows states to regulate affected EGUs through flexible regulatory approaches that do not require affected EGUs to incur large capital costs (e.g., averaging and trading programs). Under the EPA's proposed approach—establishing state goals and providing states with flexibility in plan design—states have flexibility to make exactly the kind of judgments necessary to avoid requirements that would result in stranded assets.

Remaining useful life and other factors, because of their facility-specific nature, are potentially relevant in determining requirements that are directly applicable to affected EGUs. For all of the reasons above, the agency believes that the issue of remaining useful life will arise infrequently in the development of state plans to limit CO_2 emissions from affected existing EGUs. Even if relief is due a particular facility, the state has an available toolbox of emission reduction methods that it can use to develop a section 111(d) plan that meets its emissions performance goal on time. The EPA therefore proposes that the remaining useful life of affected EGUs, and the other facility-specific factors identified in the existing implementing regulations, should not be considered as a basis for adjusting a state emission performance goal or for relieving a state of its obligation to develop and submit an approvable plan that achieves that goal on time. The agency solicits comment on this position.

10. Design, Equipment, Work Practice, or Operational standards

In this section, we discuss whether state plans may include design, equipment, work practice, or operational standards.

CAA section 111(h)(1) authorizes the Administrator to promulgate ''a design, equipment, work practice, or operational standard, or combination thereof,'' if in his or her judgment, ''it is not feasible to prescribe or enforce a standard of performance.'' CAA section 111(h)(2) provides the circumstances under which prescribing or enforcing a standard of performance is ''not feasible'': generally, when the pollutant cannot be emitted through a conveyance designed to emit or capture the pollutant, or when there is no practicable measurement methodology for the particular class of sources. Other provisions in section 111(h) further provide that a design, equipment, work practice, or operational standard (i) must ''be promulgated in the form of a standard of performance whenever it becomes feasible'' to do so,[307] and (ii) must ''be treated as a standard of performance'' for purposes of, in general, the CAA.[308]

As noted above, CAA section 111(d) requires that state plans ''establish[] standards of performance'' as well as ''provide[] for the implementation and enforcement of such standards of performance.'' CAA section 111(d) is silent as to whether (i) states may include design, equipment, work practice, or operational standards, or (ii) they may include those types of standards, but only under the limited circumstances described in section 111(h) (i.e., when it is ''not feasible'' to prescribe or enforce a standard of performance). Similarly, section 111(h) applies by its terms when the Administrator is authorized to prescribe standards of performance (which would include rulemaking under CAA section 111(b)), but is silent as to whether it

[305] The agency requests comment on whether there are circumstances other than a major capital investment that could lead to a prospective state plan imposing unreasonable costs considering a facility's remaining useful life. Where annual costs predominate and/or capital costs do not constitute a major expense, the EPA believes that the remaining useful life of an affected EGU will not significantly affect its annualized cost of control and therefore should not be a factor in determining control requirements for the EGU.

[306] Heat rate improvement methods and related capital costs are discussed in the GHG Abatement Measures TSD; SO_2 scrubber capital costs are from the documentation for the EPA's IPM Base Case v5.13, Chapter 5, Table 5–3, available at *http://www.epa.gov/powersectormodeling/BaseCasev513.html*

[307] CAA section 111(h)(4).

[308] CAA section 111(h)(5).

applies to state plans under CAA section 111(d).[309]

We invite consideration of the proper interpretation of CAA sections 111(d) and (h), under either *Chevron* step 1 or step 2, specifically: (i) Do the provisions of section 111(d) preclude state plans from including ''design, equipment, work practice, or operational standard[s]'' unless those things can be considered ''standards of performance'' or as providing for the implementation and enforcement of such standards? As a related matter, do the references to ''standard[s] of performance'' in CAA section 111(h) indicate that design, equipment, work practice, or operational standards cannot be considered ''standards of performance?'' (ii) Alternatively, are state plans authorized to include those design, equipment, work practice, or operational standards, but only under the limited circumstances described in CAA section 111(h) relating to infeasibility? (iii) As another alternative, are state plans authorized to include design, equipment, work practice, or operational standards under all circumstances, so that the limits of CAA section 111(h) do not apply? Finally, to the extent there is legal uncertainty over whether, and under what circumstances, state plans may include those standards, should the EPA authorize state plans to include them, on the understanding that if the Court invalidates the EPA's interpretation, states would be required to revise their plans accordingly without further rulemaking from the EPA?

11. Emissions Averaging and Trading

In this section, we discuss why CAA section 111(d) plans may include standards of performance that authorize emissions averaging and trading.

CAA section 111(d) authorizes state plans to include ''standards of performance'' and measures that implement and enforce those standards of performance. CAA section 111(a)(1) defines a ''standard of performance'' as ''a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction . . . adequately demonstrated.'' CAA section 302 contains a set of definitions that apply ''[w]hen used in [the Clean Air Act],'' including subsection (l), which provides a separate definition of ''standard of performance'' as ''a requirement of continuous emission reduction. . .''

The EPA proposes that the definition of ''standard of performance'' is broad enough to incorporate emissions averaging and trading provisions, including both emission rate programs, in which sources may average or trade those rates, and mass emission limit programs, in which sources may buy and sell mass emission allowances (and, under certain circumstances, offsets).[310] The term ''standard'' in the phrase ''standard for emissions of air pollutants'' is not defined in the CAA. As the Supreme Court noted in a CAA case, a ''standard'' is simply ''that which 'is established by authority, custom, or general consent, as a model or example; criterion; test.' ''[311] A tradable emission rate or a tradable mass limit is a ''standard for emissions of air pollutants'' because it establishes an emissions limit for a source's air pollutants, and as a result, qualifies as a ''criterion'' or ''test'' for those air pollutants.

Moreover, although there may be doubt that the definition of ''standard of performance'' in CAA section 302(l) applies to CAA section 111(d) in light of the fact that the definition of the same term in CAA section 111(a)(1) is more specific, even if the CAA section 302(l) definition does apply, an averaging or trading requirement qualifies as a ''continuous emission reduction'' because, in the case of a tradable emission rate, the rate is applicable at all times, and, in the case of a tradable mass limit, the source is always under the obligation that its emissions be covered by allowances.

It should be noted that the EPA has promulgated two other CAA section 111(d) rulemakings that authorized state plans to include emissions averaging or trading.[312]

G. Additional Factors That Can Help State Meet Their CO_2 Emission Performance Goals

A resource available from the EPA for states pursuing market-based approaches is the EPA's data and experience in support of state trading programs and emissions data collection. For states needing technical assistance with data or operation of market-based programs, existing EPA data systems are a resource that have been used to collect emissions data, track allowances and transfers, and determine compliance for state programs. For example, New Hampshire was part of the Ozone Transport Commission (OTC) trading program but was not included in the NOx SIP Call. Because the state wanted its sources to continue to participate in a state trading program, the EPA operated the emissions trading program for New Hampshire sources, from allocating allowances to compliance determination.

Additionally, as noted elsewhere in this preamble, more than 25 states have mandatory renewable portfolio standards, and other states have voluntary renewable programs and goals. There is considerable diversity among the states in the scope and coverage of these standards, in particular in how renewable resources are defined. At the federal level, the EPA has considered the greenhouse gas implications related to biomass use at stationary sources through several actions, including a call for information from stakeholders and the development and review of the ''Accounting Framework for Biogenic CO_2 Emissions from Stationary Sources,'' issued in September 2011. That study was reviewed by the EPA's Science Advisory Board in 2011 and 2012 and the agency continues to assess the framework and consider the latest scientific analyses and technical input received from stakeholders. The EPA expects that the framework, when finalized, will be a resource that could help inform states in the development of their CAA section 111(d) plans.

H. Resources for States To Consider in Developing Their Plans

As part of the stakeholder outreach process, the EPA asked states what the agency could do to facilitate state plan development and implementation. Some states indicated that they wanted the EPA to create resources to assist with state plan development, especially resources related to accounting for end-use energy efficiency and renewable energy (EE/RE) in state plans. They requested clear methodologies for

[309] It should be noted that section 111(b)(5), which concerns controls promulgated by the Administrator for new and modified sources, does refer to section 111(h).

[310] Typically, in a mass emission limit trading program, sources are required to obtain an allowance for each measure (e.g., ton) of air pollutant they emit. The acid rain program under Title IV of the CAA is an example of this type of trading program.

[311] *Engine Mfrs. Ass'n* v. *South Coast Air Quality Mgmt. Dist.,* 541 U.S. 246, 252–53 (2004) (quoting *Webster's Second International Dictionary,* at 2455 (1945))

[312] *See* ''Standards of Performance for New and Existing Stationary Sources: Electric Utility Steam Generating Units, Final Rule,'' 70 FR 28,606 (May 18, 2005) [also known as the Clean Air Mercury Rule, or ''CAMR''], *vacated on other grounds by New Jersey* v. *EPA,* 517 F.3d 574 (D.C. Cir. 2008), *cert denied sub nom. Util. Air Reg. Grp.* v. *New Jersey,* 555 U.S. 1169 (2009); ''Standards of Performance for New Stationary Sources and Emission Guidelines for Existing Sources; Municipal Waste Combustors,'' 60 FR 65,387 (Dec. 19, 1995) (trading rules codified in 40 CFR 60.33b(d)(1)–(2)).

measuring EE/RE policies and programs, so that these could be included as part of their compliance strategies. Stakeholders said that these tools and metrics should build upon the EPA's ''Roadmap for Incorporating Energy Efficiency/Renewable Energy Policies and Programs into State and Tribal Implementation Plans,''[313] as well as the State Energy Efficiency Action Network's ''Energy Efficiency Program Impact Evaluation Guide.''[314] The EPA also heard that states would like examples of effective state policies and programs.

As a result of this feedback, in consultation with U.S. Department of Energy and other federal agencies, the EPA has developed a toolbox of decision support resources and is making that available at a dedicated Web site: *http://www2.epa.gov/www2.epa.gov/cleanpowerplantoolbox.* Current resources on the site focus on approaches states and other entities have already taken that reduce CO_2 emissions from the electric utility sector.

For the final rulemaking, the EPA plans to organize resources on the Web site around the following two categories: State plan guidance and state plan decision support. The state plan guidance section will serve as a central repository for the final emission guidelines, regulatory impact analysis, technical support documents, and other supporting materials. The state plan decision support section will include information to help states evaluate different approaches and measures they might consider as they initiate plan development. This section will include, for example, a summary of existing state climate and EE/RE policies and programs,[315] National Action Plan for Energy Efficiency (Action Plan),[316] information on electric utility actions that reduce CO_2, and tools and information to assist with translating energy savings into emission reductions.

We note that our inclusion of a measure in the toolbox does not mean that a state plan must include that measure. In fact, inclusion of measures provided at the Web site does not necessarily imply the approvability of an approach or method for use in a state plan. States will need to demonstrate that any measure included in a state plan meets all relevant approvability criteria and adequately addresses elements of the plan components discussed in Section VIII of this preamble.

The EPA solicits comment on this approach and the information currently included, and planned for inclusion, in the Decision Support Toolbox.

IX. Implications for Other EPA Programs and Rules

A. Implications for New Source Review Program

The new source review (NSR) program is a preconstruction permitting program that requires major stationary sources of air pollution to obtain permits prior to beginning construction. The requirements of the NSR program apply both to new construction and to modifications of existing major sources. Generally, a source triggers these permitting requirements as a result of a modification when it undertakes a physical or operational change that results in a significant emission increase and a net emissions increase. NSR regulations define what constitutes a significant net emissions increase, and the concept is pollutant-specific. For GHG emissions, the PSD applicability analysis is described in the Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule (FR 75 31514, June 3, 2010). As a general matter, a modifying major stationary source would trigger PSD permitting requirements for GHGs if it emits GHGs in excess of 100,000 tons per year (tpy) of carbon dioxide equivalents (CO_2e), and it undergoes a change or change in the method of operation (modification) resulting in an emissions increase of 75,000 tpy CO_2e as well as an increase on a mass basis. Once it has been determined that a change triggers the requirements of the NSR program, the source must obtain a permit prior to making the change. The pollutant(s) at issue and the air quality designation of the area where the facility is located or proposed to be built determine the specific permitting requirements.

As part of its CAA section 111(d) plan, a state may impose requirements that require an affected EGU to undertake a physical or operational change to improve the unit's efficiency that results in an increase in the unit's dispatch and an increase in the unit's annual emissions. If the emissions increase associated with the unit's changes exceeds the thresholds in the NSR regulations discussed above for one or more regulated NSR pollutants, including the netting analysis, the changes would trigger NSR.

While there may be instances in which an NSR permit would be required, we expect those situations to be few. As previously discussed in this preamble, states have considerable flexibility in selecting varied measures as they develop their plans to meet the goals of the emissions guidelines. One of these flexibilities is the ability of the state to establish the standards of performance in their CAA section 111(d) plans in such a way so that their affected sources, in complying with those standards, in fact would not have emissions increases that trigger NSR. To achieve this, the state would need to conduct an analysis consistent with the NSR regulatory requirements that supports its determination that as long as affected sources comply with the standards of performance in their CAA section 111(d) plan, the source's emissions would not increase in a way that trigger NSR requirements.

For example, a state could decide to adjust its demand side measures or increase reliance on renewable energy as a way of reducing the future emissions of an affected source initially predicted (without such alterations) to increase its emissions as a result of a CAA section 111(d) plan requirement. In other words, a state plan's incorporation of expanded use of cleaner generation or demand-side measures could yield the result that units that would otherwise be projected to trigger NSR through a physical change that might result in increased dispatch would not, in fact, increase their emissions, due to reduced demand for their operation. The state could also, as part of its CAA section 111(d) plan, develop conditions for a source expected to trigger NSR that would limit the unit's ability to move up in the dispatch enough to result in a significant net emissions increase that would trigger NSR (effectively establishing a synthetic minor limit). [317]

We request comment on whether, with adequate record support, the state plan could include a provision, based on underlying analysis, stating that an affected source that complies with its applicable standard would be treated as not increasing its emissions, and if so, whether such a provision would mean that, as a matter of law, the source's actions to comply with its standard

[313] *http://epa.gov/airquality/eere/.*

[314] *http://www1.eere.energy.gov/seeaction/index.html.*

[315] Appendix, State Plan Considerations TSD.

[316] *http://www.epa.gov/cleanenergy/energy-programs/suca/resources.html.*

[317] Certain stationary sources that emit or have the potential to emit a pollutant at a level that is equal to or greater than specified thresholds are subject to major source requirements. *See, e.g.,* CAA §§ 165(a)(1), 169(1), 501(2), 502(a). A synthetic minor limitation is a legally and practicably enforceable restriction that has the effect of limiting emissions below the relevant level and that a source voluntarily obtains to avoid major stationary source requirements, such as the PSD or title V permitting programs. *See, e.g.,* 40 CFR 52.21(b)(4), 51.166(b)(4), 70.2 (definition of ''potential to emit'').

would not subject the source to NSR. We also seek comment on the level of analysis that would be required to support a state's determination that sources will not trigger NSR when complying with the standards of performance included in the state's CAA section 111(d) plan and the type of plan requirements, if any, that would need to be included in the state's plan.

As a result of such flexibility and anticipated state involvement, we expect that a limited number of affected sources would trigger NSR when states implement their plans.

B. Implications for Title V Program

The preamble to the re-proposed EGU NSPS (70 FR 1429–1519; January 8, 2014) explained that regulating GHGs for the first time under section 111 of the CAA would make GHGs ''regulated air pollutants'' for the first time under the operating permit regulations of 40 CFR parts 70 and 71. This would result in GHGs becoming ''fee pollutants'' in certain state part 70 permit programs and in the EPA's part 71 permit program, thus requiring the collection of fees for GHG emissions in these programs. Where title V fees would be required for GHGs, they would typically be charged at the same rate ($ per ton of pollutant) as all other fee pollutants. This would likely result in excessive and unnecessary fees being charged to subject sources. To avoid this situation, we proposed to exempt GHGs from the fee rates in effect for other fee pollutants, while proposing an alternative fee that would be much lower than the fee charged to other fee pollutants, yet sufficient to cover the costs of addressing GHGs in operating permits.

This title V fee issue is a one-time occurrence resulting from the promulgation of the first CAA section 111 standard to regulate GHGs (the EGU NSPS for new sources) and is not an issue for any other subsequent CAA section 111 regulations, so there is no need to address any title V fee issues in this proposal. Thus, we are not re-visiting these title V fee issues in this proposal, and we are not proposing any additional revisions to any title V regulations as part of this action.

The title V regulations require each permit to include emission limitations and standards, including operational requirements and limitations that assure compliance with all applicable requirements. Requirements resulting from this rule that are imposed on affected EGUs or any other potentially affected entities that have title V operating permits are applicable requirements under the title V regulations and would need to be incorporated into the source's title V permit in accordance with the schedule established in the title V regulations. For example, if the permit has a remaining life of three years or more, a permit reopening to incorporate the newly applicable requirement shall be completed no later than 18 months after promulgation of the applicable requirement. If the permit has a remaining life of less than three years, the newly applicable requirement must be incorporated at permit renewal.

C. Interactions With Other EPA Rules

Existing fossil fuel-fired EGUs, such as those covered in this proposal, are or will be potentially impacted by several other recently finalized or proposed EPA rules.[318] On February 16, 2012, the EPA issued the mercury and air toxics standards (MATS) rule (77 FR 9304) to reduce emissions of toxic air pollutants from new and existing coal- and oil-fired EGUs. The MATS rule will reduce emissions of heavy metals, including mercury (Hg), arsenic (As), chromium (Cr), and nickel (Ni); and acid gases, including hydrochloric acid (HCl) and hydrofluoric acid (HF). These toxic air pollutants, also known as hazardous air pollutants or air toxics, are known or suspected of causing damage to the nervous system, cancer, and other serious health effects. The MATS rule will also reduce SO_2 and fine particle pollution, which will reduce particle concentrations in the air and prevent thousands of premature deaths and tens of thousands of heart attacks, bronchitis cases and asthma episodes.

The EPA is closely monitoring MATS compliance and finds that the industry is making substantial progress. Plant owners are moving proactively to install controls that will achieve the MATS performance standards. Certain units, especially those that operate infrequently, may be considered not worth investing in given today's electricity market, and those are closing.

Existing sources subject to the MATS rule are given until April 16, 2015 to comply with the rule's requirements. The final MATS rule provided a foundation on which states and other permitting authorities could rely in granting an additional, fourth year for compliance provided for by the CAA. States report that these fourth year extensions are being granted. In addition, the EPA issued an enforcement policy that provides a clear pathway for reliability-critical units to receive an administrative order that includes a compliance schedule of up to an additional year, if it is needed to ensure electricity reliability.

On May 19, 2014, the EPA issued a final rule under section 316(b) of the Clean Water Act (33 U.S.C. 1326(b)) (referred to hereinafter as the 316(b) rule).[319] This rule establishes new standards to reduce injury and death of fish and other aquatic life caused by cooling water intake structures at existing power plants and manufacturing facilities.[320] The 316(b) rule subjects existing power plants and manufacturing facilities that withdraw in excess of 2 million gallons per day (MGD) of cooling water, and use at least 25 percent of that water for cooling purposes, to a national standard designed to reduce the number of fish destroyed through impingement and a national standard for establishing entrainment reduction requirements. All facilities subject to the rule must submit information on their operations for use by the permit authority in determining 316(b) permit conditions. Certain plants that withdraw very large volumes of water will also be required to conduct additional studies for use by the permit authority in determining the site-specific entrainment reduction measures for such facilities. The rule provides significant flexibility for compliance with the impingement standards and, as a result, is not projected to impose a substantial cost burden on affected facilities. With respect to entrainment, the rule calls upon the permitting authority to in establishing appropriate entrainment reduction measures, taking into account, among other factors, compliance costs, facility reliability and grid reliability. Existing sources subject to the 316(b) rule are required to comply with the impingement requirements as soon as practicable after the entrainment requirements are determined. They must comply with applicable site-specific entrainment reduction controls based on the schedule of requirements established by the permitting authority.

The EPA is also reviewing public comments and working to finalize two proposed rules which will also impact

[318] We discuss other rulemakings solely for background purposes. The effort to coordinate rulemakings is not a defense to a violation of the CAA. Sources cannot defer compliance with existing requirements because of other upcoming regulations.

[319] The pre-publication version of the final rule is available at: *http://water.epa.gov/lawsregs/lawsguidance/cwa/316b/#final*.

[320] CWA section 316(b) provides that standards applicable to point sources under sections 301 and 306 of the Act must require that the location, design, construction and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impacts.

existing fossil fuel-fired EGUs: The steam electric effluent limitation guidelines (SE ELG) rule and the coal combustion residuals (CCR) rule. These proposed rules are summarized below.

On June 7, 2013 (78 FR 34432), the EPA proposed the SE ELG rule to strengthen the controls on discharges from certain steam electric power plants by revising technology-based effluent limitations guidelines and standards for the steam electric power generating point source category. The current regulations, which were last updated in 1982, do not adequately address the toxic pollutants discharged from the electric power industry, nor have they kept pace with process changes that have occurred over the last three decades. Existing steam electric power plants currently contribute 50–60 percent of all toxic pollutants discharged to surface waters by all industrial categories regulated in the United States under the CWA. Furthermore, power plant discharges to surface waters are expected to increase as pollutants are increasingly captured by air pollution controls and transferred to wastewater discharges. This proposed regulation, which includes new requirements for both existing and new generating units, would reduce the amount of toxic metals and other pollutants discharged to surface waters from power plants.

On June 21, 2010 (75 FR 35128), the EPA proposed the CCR rule, which co-proposed two approaches to regulating the disposal of coal combustion residuals (CCRs) generated by electric utilities and independent power producers. CCRs are residues from the combustion of coal in steam electric power plants and include materials such as coal ash (fly ash and bottom ash) and flue gas desulfurization (FGD) wastes. Under one proposed approach, the EPA would list these residuals as ‘‘special wastes,’’ when destined for disposal in landfills or surface impoundments, and would apply the existing regulatory requirements established under Subtitle C of RCRA to such wastes. Under the second proposed approach, the EPA would establish new regulations applicable specifically to CCRs under subtitle D of RCRA, the section of the statute applicable to solid (i.e., non-hazardous) wastes. Under both approaches, CCRs that are beneficially used would remain exempt under the Bevill exclusion.[321]

While the EPA still is evaluating all the available information and comments, and while a final risk assessment for the CCR rule has not yet been completed, reliance on data and analyses discussed in the preamble to the recent SE ELG proposal might have the potential to lower the CCR rule risk assessment results by as much as an order of magnitude. If this proves to be the case, the EPA's current thinking is that the revised risks, coupled with the ELG requirements that the agency might promulgate, and the increased federal oversight such requirements could achieve, could provide strong support for a conclusion that regulation of CCR disposal under RCRA Subtitle D would be adequate.[322] The EPA is under a court-ordered deadline to complete the CCR rulemaking by December 19, 2014.

The EPA recognizes the importance of assuring that each of the rules described above can achieve its intended environmental objectives in a commonsense, cost-effective manner, consistent with underlying statutory requirements, and while assuring a reliable power system. Executive Order (EO) 13563, ‘‘Improving Regulation and Regulatory Review,’’ issued on January 18, 2011, states that ‘‘[i]n developing regulatory actions and identifying appropriate approaches, each agency shall attempt to promote . . . coordination, simplification, and harmonization. Each agency shall also seek to identify, as appropriate, means to achieve regulatory goals that are designed to promote innovation.’’ Within the EPA, we are paying careful attention to the interrelatedness and potential impacts on the industry, reliability and cost that these various rulemakings can have.

As discussed in Sections VII and VIII of this preamble, the EPA is proposing to give states broad flexibility in developing approvable plans under CAA section 111(d), including the ability to adopt rate-based or mass-based emission performance goals, and to rely on a wide variety of CO_2 emission reduction measures. The EPA is also proposing to give states considerable flexibility with respect to the timeframes for plan development and implementation, with up to two or three years permitted for final plans to be submitted after the proposed GHG emission guidelines are finalized, and up to fifteen years for all emission reduction measures to be fully implemented. In light of these flexibilities, we believe that states will have ample opportunity, when developing and implementing their CAA section 111(d) plans, to coordinate their response to this requirement with source and state responses to any obligations that may be applicable to affected EGUs as a result of the MATS, 316(b), SE ELG and CCR rules—all of which are or will be final rules before this rulemaking is finalized—and to do so in a manner that will help reduce cost and ensure reliability, while also ensuring that all applicable environmental requirements are met.[323]

The EPA is also endeavoring to enable EGUs to comply with applicable obligations under other power sector rules as efficiently as possible (e.g., by facilitating their ability to coordinate planning and investment decisions with respect to those rules) and, where possible, implement integrated compliance strategies. For example, in the proposed SE ELG rule, the EPA describes its current thinking on how it might effectively harmonize the potential requirements of that rule with the requirements of the final CCR rule, to the extent that both rules may regulate or affect the disposal of coal combustion wastes to and from surface impoundments at power plants.[324] The EPA's goal in exploring how it might harmonize the SE ELG and CCR rules is to minimize the overall complexity of the two regulatory structures and avoid creating unnecessary burdens.[325]

[321] Beneficial use involves the reuse of CCRs in a product to replace virgin raw materials that would otherwise be obtained through extraction. The EPA encourages the beneficial use of CCRs in an appropriate and protective manner, because this practice can produce environmental, economic, and performance benefits. The Agency recently evaluated the environmental impacts associated with encapsulated beneficial uses of fly ash used as a direct substitute for Portland cement in concrete, and FGD gypsum used as a replacement for mined gypsum in wallboard. The EPA concluded that the beneficial use of CCRs in concrete and wallboard is appropriate because the environmental releases of constituents of potential concern (COPC) during use by the consumer are comparable to or lower than those from analogous non-CCR products, or are at or below relevant regulatory and health-based benchmarks for human and ecological receptors. *See* U.S. Environmental Protection Agency, *Coal Combustion Residual Beneficial Use Evaluation: Fly Ash Concrete and FGD Gypsum Wallboard* (2014).

[322] U.S. EPA. September 2013. Regulatory Impact Analysis for the Proposed Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units. EPA–452/R–13–003. Available at *http://www2.epa.gov/sites/production/files/2013–09/documents/20130920proposalria.pdf.*

[323] It should be noted that regulatory obligations imposed upon states and sources operate independently under different statutes and sections of statutes; the EPA expects that states and sources will take advantage of available flexibilities as appropriate, but will comply with all relevant legal requirements.

[324] See: **Federal Register** Vol. 78, No. 110; June 7, 2013. Page 34441.

[325] In considering how to coordinate the potential requirements between the SE ELG and CCR rules, the EPA stated that it is guided by the following policy considerations: First and foremost, the EPA intends to ensure that its statutory responsibilities to restore and maintain water quality under the CWA and to protect human health and the environment under RCRA are fulfilled. At the same time, the EPA would seek to minimize the potential

In addition to the power sector rules discussed above, the development of SIPs for criteria pollutants ($PM_{2.5}$, ozone and SO_2) and regional haze may also have implications for existing fossil-fired EGUs.

On June 6, 2013, the EPA proposed an implementation rule for the 2008 ozone National Ambient Air Quality Standards (NAAQS), to provide rules and guidance to states on the development of approvable state implementation plans (SIPs), including SIPs under CAA section 110 (infrastructure SIPs) and section 182 (ozone nonattainment SIPs). This rule addresses the statutory requirements for areas that the EPA has designated as nonattainment for the 2008 ozone standard. The agency is currently working to finalize that rule. The EPA is also working on a proposed transport rule that would identify the obligations of upwind states that contribute to those downwind state ozone nonattainment areas. This rule is scheduled for proposal in 2014 and to be finalized by 2015.

The EPA is developing a proposed implementation rule to provide guidance to states on the development of SIPs for the 2012 $PM_{2.5}$ NAAQS.

The SO_2 NAAQS was revised in June 2010 to protect public health from the short-term effects of SO_2 exposure. In July 2013, the EPA designated 29 areas in 16 states as nonattainment for the SO_2 NAAQS. The EPA based these nonattainment designations on the most recent set of certified air quality monitoring data as well as an assessment of nearby emission sources and weather patterns that contribute to the monitored levels. The EPA intends to address the designations for all other areas in separate actions in the future [326]. The EPA has proposed the data requirements rule for the 1-hour SO_2 NAAQS to require states to characterize air quality more extensively using ambient monitoring or air quality modeling approaches.

The EPA requires SIP updates every 10 years for regional haze, as required by the EPA's Regional Haze Rule which was promulgated in 1999. The next 10-year SIP revision for regional haze, covering the time period through 2028, is due from each state by July 2018. Each SIP must provide for reasonable progress towards visibility improvement in protected scenic areas.

The development of these SIPs may, where applicable, have significant implications for existing fossil fuel-fired EGUs, as well as for the states that are responsible for developing them. The timeframes for submittal of SIPs for the various programs and the timeframes we are proposing for submittal of the CAA section 111(d) state plans will allow considerable time for coordination by states in the development of their respective plans. The EPA is willing to work with states to assist them in coordinating their efforts across these planning processes. The EPA believes that CAA section 111(d) efforts and actions will tend to contribute to overall air quality improvements and thus should be complementary to criteria pollutant and regional haze SIP efforts.

In light of the broad flexibilities we are proposing in this action, we believe that states will have ample opportunity to design CAA section 111(d) plans that use innovative, cost-effective regulatory strategies and that spark investment and innovation across a wide variety of clean energy technologies. We also believe that the broad flexibilities we are proposing in this action will enable states and affected EGUs to build on their longstanding, successful records of complying with multiple CAA, CWA, and other environmental requirements, while assuring an adequate, affordable, and reliable supply of electricity.

X. Impacts of the Proposed Action [327]

A. What are the air impacts?

The EPA anticipates significant emission reductions under the proposed guidelines for the power sector. CO_2 emissions are projected to be reduced when compared to 2005 emissions, by 26 percent to 27 percent in 2020 and about 30 percent in 2030 under Option 1. Option 2 reflects reductions of about 23 percent in 2020 and 23 percent to 24 percent in 2025 when compared to CO_2 emissions in 2005. The guidelines are projected to result in substantial co-benefits through reductions of SO_2, $PM_{2.5}$ and NOx that will have direct public health benefits by lowering ambient levels of these pollutants and ozone. Tables 10 and 11 show expected CO_2 and other air pollutant emission reductions in the base case, with the proposed Option 1 for 2020, 2025, and 2030 and regulatory alternative Option 2, for 2020 and 2025.

TABLE 10—SUMMARY OF CO_2 AND OTHER AIR POLLUTANT EMISSION REDUCTIONS WITH OPTION 1

	CO_2 (million metric tons)	SO_2 (thousands of tons)	NO_X (thousands of tons)	$PM_{2.5}$ (thousands of tons)
2020 Regional Compliance Approach:				
Base Case Proposed	2,161	1,476	1,559	212
Guidelines:	1,790	1,184	1,213	156
Emission Reductions	371	292	345	56
2025 Regional Compliance Approach:				
Base Case Proposed	2,231	1,515	1,587	209
Guidelines:	1,730	1,120	1,166	150

for overlapping requirements to avoid imposing any unnecessary burdens on regulated entities and to facilitate implementation and minimize the overall complexity of the regulatory structure under which facilities must operate. Based on these considerations, the EPA stated that it is exploring two primary means of integrating the two rules: (1) Through coordinating the design of any final substantive CCR regulatory requirements, and (2) through coordination of the timing and implementation of final rule requirements to provide facilities with a reasonable timeline for implementation that allows for coordinated planning and protects electricity reliability for consumers.

[326] The EPA has developed a comprehensive implementation strategy for these future actions that focuses resources on identifying and addressing unhealthy levels of SO_2 in areas where people are most likely to be exposed to violations of the standard. The strategy is available at: *http://www.epa.gov/airquality/sulfurdioxide/implement.html.*

[327] The impacts presented in this section of the preamble represent an illustrative implementation of the guidelines. As states implement the proposed guidelines, they have sufficient flexibility to adopt different state-level or regional approaches that may yield different costs, benefits, and environmental impacts. For example, states may use the flexibilities described in these guidelines to find approaches that are more cost effective for their particular state or choose approaches that shift the balance of co-benefits and impacts to match broader state priorities.

TABLE 10—SUMMARY OF CO_2 AND OTHER AIR POLLUTANT EMISSION REDUCTIONS WITH OPTION 1—Continued

	CO_2 (million metric tons)	SO_2 (thousands of tons)	NO_X (thousands of tons)	$PM_{2.5}$ (thousands of tons)
Emission Reductions	501	395	421	59
2030 Regional Compliance Approach:				
Base Case Proposed	2,256	1,530	1,537	198
Guidelines:	1,711	1,106	1,131	144
Emission Reductions	545	424	407	54
2020 State Compliance Approach:				
Base Case Proposed	2,161	1,476	1,559	212
Guidelines:	1,777	1,140	1,191	154
Emission Reductions	383	335	367	58
2025 State Compliance Approach:				
Base Case Proposed	2,231	1,515	1,587	209
Guidelines:	1,724	1,090	1,151	145
Emission Reductions	506	425	436	63
2030 State Compliance Approach:				
Base Case Proposed	2,256	1,530	1,537	198
Guidelines:	1,701	1,059	1,109	142
Emission Reductions	555	471	428	56

Source: Integrated Planning Model, 2014.

TABLE 11—SUMMARY OF CO_2 AND AIR POLLUTANT EMISSION REDUCTIONS WITH OPTION 2

	CO_2 (million metric tons)	SO_2 (thousands of tons)	NO_X (thousands of tons)	$PM_{2.5}$ (thousands of tons)
2020 Regional Compliance Approach:				
Base Case	2,161	1,476	1,559	212
Option 2	1,878	1,231	1,290	166
Emission Reductions	283	244	268	46
2025 Regional Compliance Approach:				
Base Case	2,231	1,515	1,587	209
Option 2	1,862	1,218	1,279	165
Emission Reductions	368	297	309	44
2020 State Compliance Approach:				
Base Case	2,161	1,476	1,559	212
Option 2	1,866	1,208	1,277	163
Emission Reductions	295	267	281	49
2025 State Compliance Approach:				
Base Case	2,231	1,515	1,587	209
Option 2	1,855	1,188	1,271	161
Emission Reductions	376	327	317	48

Source: Integrated Planning Model, 2014.

The reductions in these tables do not account for reductions in hazardous air pollutants (HAPs) that may occur as a result of this rule. For instance, the fine particulate reductions presented above do not reflect all of the reductions in many heavy metal particulates.

B. Comparison of Building Block Approaches

Though the EPA has determined that the 4-building block approach is the BSER, we did analyze the impacts of both a combination of building blocks 1 and 2 and the combination of all four building blocks. The analysis indicates that the combined strategies of heat rate improvements (building block 1) and re-dispatch (building block 2) would result in overall CO_2 emission reductions of approximately 22 percent in 2020 (compared to 2005 emissions and assuming state-level compliance). This compares to expected CO_2 emission reductions of approximately 27 percent for the four-block BSER approach discussed below. The EPA analysis also estimates 24–32 GW of additional coal-fired EGU retirements in 2020 (compared to 46–49 GW for the four-block approach) and an additional 3–5 GW of oil/gas steam EGUs (compared to 16 GW for the four-block approach). For both the two-block and the four-block approach, a decrease in coal production and price is predicted in 2020. The decrease in production is predicted at 20–23 percent for the two-block approach, compared to a decrease of 25–27 percent for the four-block approach. A 12 percent decrease in coal prices is predicted for the two-block approach; while the four-block approach results in a 16 to 18 percent decrease. Under both approaches, the shifting in generation from higher-emitting steam EGUs to lower-emitting NGCC units results in an increase in natural gas production and price. The two-block approach results in a production increase of 19–22 percent and a price increase of 10–11 percent. The four-block approach results in a production increase of 12–14 percent and a price increase of 9–12 percent. Both the two-block and the four-block approaches result in construction of additional NGCC capacity by 2020, with 11–18 GW of new NGCC for the two-block approach and 20–22 GW of new NGCC capacity for the four-block approach. However, while the two-block approach results in 5–17 GW of new NGCC capacity in 2030, the four-block approach results in 32–35 GW less NGCC capacity in 2030 relative to the base case (due to increased use of renewable energy sources and decreased demand from implementation of demand side energy efficiency measures). Also, significantly, the two-block approach results in less than 500 MW of new renewable energy capacity; while the four-block option results in approximately 12 GW of new renewable generating capacity.

The EPA projects that the annual incremental compliance cost for the building block 1 and 2 approach is estimated to be $3.2 to $4.4 billion in 2020 and $6.8 to $9.8 billion (2011$) in 2030, excluding the costs associated with monitoring, reporting, and recordkeeping (MRR). This compares to costs excluding MRR of $5.4 to $7.4 billion in 2020 and $7.3 to $8.8 billion in 2030 for the proposed Option 1 (2011$) as discussed in Section X.E of this preamble.

The total combined climate benefits and health co-benefits for the building block 1 and 2 approach are estimated to be $21 to $40 billion in 2020 and $32 to $63 billion in 2030 (2011$ at a 3-percent discount rate [model average]). The net benefits are estimated to be $18 to $36 billion in 2020 and $25 to $53 billion in 2030 (2011$ at a 3-percent discount rate [model average]). For the purposes of this summary, we list the climate benefits associated with the marginal value of the model average at 3% discount rate, however we emphasize the importance and value of considering the full range of SCC values. These building block 1 and 2 benefit estimates compare to combined climate benefits and health co-benefits of $33 to $57 billion in 2020 and $55 to $93 billion in 2030 (2011$ at a 3-percent discount rate [model average]) for the proposed Option 1. Net benefits are estimated to be $27 to $50 billion in 2020 and $48 to $84 billion in 2030 (2011$ at a 3-percent discount rate [model average]) as discussed in Section X.G. and XI.A of this preamble.[328]

C. Endangered Species Act

Consistent with the requirements of section 7(a)(2) of the Endangered Species Act (ESA), the EPA has also considered the effects of this proposed rule and has reviewed applicable ESA regulations, case law, and guidance to determine what, if any, impact there may be to listed endangered or threatened species or designated critical habitat. Section 7(a)(2) of the ESA requires federal agencies, in consultation with the U.S. Fish and Wildlife Service (FWS) and/or the National Marine Fisheries Service, to ensure that actions they authorize, fund, or carry out are not likely to jeopardize the continued existence of federally listed endangered or threatened species or result in the destruction or adverse modification of designated critical habitat of such species. 16 U.S.C. 1536(a)(2). Under relevant implementing regulations, section 7(a)(2) applies only to actions where there is discretionary federal involvement or control. 50 CFR 402.03. Further, under the regulations consultation is required only for actions that ''may affect'' listed species or designated critical habitat. 50 CFR § 402.14. Consultation is not required where the action has no effect on such species or habitat. Under this standard, it is the federal agency taking the action that evaluates the action and determines whether consultation is required. *See* 51 FR 19926, 19949 (June 3, 1986). Effects of an action include both the direct and indirect effects that will be added to the environmental baseline. 50 CFR 402.02. Indirect effects are those that are caused by the action, later in time, and are reasonably certain to occur. *Id.* To trigger a consultation requirement, there must thus be a causal connection between the federal action, the effect in question, and the listed species, and the effect must be reasonably certain to occur.

The EPA has considered the effects of this proposed rule and has reviewed applicable ESA regulations, case law, and guidance to determine what, if any, impact there may be to listed species or designated critical habitat for purposes of section 7(a)(2) consultation. The EPA notes that the projected environmental effects of this proposal are positive: reductions in overall GHG emissions, and reductions in PM and ozone-precursor emissions (SO_X and NO_X). With respect to the projected GHG emission reductions, the EPA does not believe that such reductions trigger ESA consultation requirements under section 7(a)(2). In reaching this conclusion, the EPA is mindful of significant legal and technical analysis undertaken by FWS and the U.S. Department of the Interior in the context of listing the polar bear as a threatened species under the ESA. In that context, in 2008, FWS and DOI expressed the view that the best scientific data available were insufficient to draw a causal connection between GHG emissions and effects on the species in its habitat.[329] The DOI Solicitor concluded that where the effect at issue is climate change, proposed actions involving GHG emissions cannot pass the ''may affect'' test of the section 7 regulations and thus are not subject to ESA consultation. The EPA has also previously considered issues relating to GHG emissions in connection with the requirements of ESA section 7(a)(2). Although the GHG emission reductions projected for this proposal are large (the highest estimate is reductions of 555 MMT of CO_2 in 2030—see Table 10 above), the EPA evaluated larger reductions in assessing this same issue in the context of the light duty vehicle GHG emission standards for model years 2012–2016 and 2017–2025. There the agency projected emission reductions roughly double and four times those projected

[328] Note that the health co-benefits and net benefits for the proposed Option 1 include PM co-benefits associated with directly emitted $PM_{2.5}$. In contrast, the building block 1 and 2 analysis does not include co-benefits related to directly emitted $PM_{2.5}$.

[329] *See, e.g.,* 73 FR 28212, 28300 (May 15, 2008); Memorandum from David Longly Bernhardt, Solicitor, U.S. Department of the Interior re: ''Guidance on the Applicability of the Endangered Species Act's Consultation Requirements to Proposed Actions Involving the Emission of Greenhouse Gases'' (Oct. 3, 2008).

here over the lifetimes of the model years in question [330] and, based on air quality modeling of potential environmental effects, concluded that ''EPA knows of no modeling tool which can link these small, time-attenuated changes in global metrics to particular effects on listed species in particular areas. Extrapolating from global metric to local effect with such small numbers, and accounting for further links in a causative chain, remain beyond current modeling capabilities.'' EPA, *Light Duty Vehicle Greenhouse Gas Standards and Corporate Average Fuel Economy Standards,* Response to Comment Document for Joint Rulemaking at 4–102 (Docket EPA–OAR–HQ–2009–4782). The EPA reached this conclusion after evaluating issues relating to potential improvements relevant to both temperature and oceanographic pH outputs. The EPA's ultimate finding was that ''any potential for a specific impact on listed species in their habitats associated with these very small changes in average global temperature and ocean pH is too remote to trigger the threshold for ESA section 7 (a)(2).'' *Id.* The EPA believes that the same conclusions apply to the present proposal, given that the projected CO_2 emission reductions are less than those projected for either of the light duty vehicle rules. *See, e.g., Ground Zero Center for Non-Violent Action* v. *U.S. Dept. of Navy,* 383 F. 3d 1082, 1091–92 (9th Cir. 2004) (where the likelihood of jeopardy to a species from a federal action is extremely remote, ESA does not require consultation).

With regard to non-GHG air emissions, the EPA is also projecting substantial reductions of SO_X and NO_X as a collateral consequence of this proposal. However, CAA section 111(d)(1) standards cannot directly control emissions of criteria pollutants. Consequently, CAA section 111(d) provides no discretion to adjust the standard based on potential impacts to endangered species of reduced criteria pollutant emissions. Section 7(a)(2) consultation thus is not required with respect to the projected reductions of criteria pollutant emissions. *See* 50 CFR 402.03; *see also, National Lime Ass'n* v. *EPA,* 233 F. 3d 625, 638–39 (D.C. Cir. 2000) (although CAA section 112(b)(2) prohibits the EPA from listing criteria pollutants as hazardous air pollutants, the EPA may use PM as a surrogate for metal hazardous air pollutants and reductions in PM do not constitute impermissible regulation of a criteria pollutant).

Moreover, there are substantial questions as to whether any potential for relevant effects results from any element of the proposed rule or would result instead from the separate actions of States establishing standards of performance for existing sources and implementing and enforcing those standards. *Cf. American Trucking Assn's* v. *EPA,* 175 F. 3d 1027, 1043–45 (D.C. Cir. 1999), *rev'd on different grounds sub nom., Whitman* v. *American Trucking Assn's,* 531 U.S. 457 (2000) (National Ambient Air Quality Standards have no economic impact, for purposes of Regulatory Flexibility Act, because impacts result from the actions of States through their development, implementation and enforcement of state implementation plans). Thus, for example, although questions may exist whether actions such as increased utilization of solar or wind power could have effects on listed species, the EPA believes that such effects (if any) would result from decisions and actions by states in developing, implementing and enforcing their plans. The precise steps States choose to take in that regard cannot be determined or ordered by this federal action, and they are not sufficiently certain to be attributable to this proposed rule for ESA purposes. Consequently, for this additional reason, the EPA does not believe that this proposed rule (if enacted) would have effects on listed species that would trigger the section 7 (a)(2) consultation requirement.

D. What are the energy impacts?

The proposed guidelines have important energy market implications. Under Option 1, average nationwide retail electricity prices are projected to increase by roughly 6 to 7 percent in 2020 relative to the base case, and by roughly 3 percent in 2030 (contiguous U.S.). Average monthly electricity bills are anticipated to increase by roughly 3 percent in 2020, but decline by approximately 9 percent by 2030. This is a result of the increasing penetration of demand-side programs that more than offset increased prices to end users by their expected savings from reduced electricity use.

The average delivered coal price to the power sector is projected to decrease by 16 to 17 percent in 2020 and roughly 18 percent in 2030, relative to the base case for Option 1. The EPA also projects that electric power sector-delivered natural gas prices will increase by 9 to 12 percent in 2020, with negligible changes in 2030. Natural gas use for electricity generation will increase by as much as 1.2 trillion cubic feet (TCF) in 2020 relative to the base case, and then begin to decline over time.

These figures reflect the EPA's illustrative modeling that presumes policies that lead to dispatch changes in 2020 and growing use of energy efficiency and renewable electricity generation out to 2029. If states make different policy choices, impacts could be different. For instance, if states implement renewable and/or energy efficiency policies on a more aggressive time-frame, impacts on natural gas and electricity prices would likely be less. Implementation of other measures not included in the EPA's BSER calculation or compliance modeling, such as nuclear uprates, transmission system improvements, use of energy storage technologies or retrofit CCS, could also mitigate gas price and/or electricity price impacts.

The EPA projects coal production for use by the power sector, a large component of total coal production, will decline by roughly 25 to 27 percent in 2020 from base case levels. The use of coal by the power sector will decrease roughly 30 to 32 percent in 2030. Renewable energy capacity is anticipated to increase by roughly 12 GW in 2020 and by 9 GW in 2030 under Option 1. Energy market impacts from the guidelines are discussed more extensively in the RIA found in the docket for this rulemaking.

E. What are the compliance costs?

The compliance costs of this proposed action are represented in this analysis as the change in electric power generation costs between the base case and the proposed rule in which states pursue a distinct set of strategies beyond the strategies taken in the base case to meet the terms of the EGU GHG emission guidelines, and include cost estimates for demand-side energy efficiency. The compliance assumptions—and, therefore, the projected compliance costs—set forth in this analysis are illustrative in nature and do not represent the full suite of compliance flexibilities states may ultimately pursue. These illustrative compliance scenarios are designed to reflect, to the extent possible, the scope and the nature of the proposed guidelines. However, there is considerable uncertainty with regards to the precise measures that states will adopt to meet the proposed requirements, because there are considerable flexibilities afforded to the states in developing their state plans.

The EPA projects that the annual incremental compliance cost of Option 1 is estimated to be between \$5.5 and \$7.5 billion in 2020 and between \$7.3

[330] See 75 FR at 25438 Table I.C 2–4 (May 7, 2010); 77 FR at 62894 Table III–68 (Oct. 15, 2012).

and $8.8 billion (2011$) in 2030, including the costs associated with monitoring, reporting, and recordkeeping (MRR). The incremental compliance cost of Option 2 is estimated to be between $4.3 and $5.5 billion in 2020, including MRR costs. In 2025, the estimated compliance cost of Option 2 is estimated to be between $4.5 and $5.5 billion (with the assumed levels of end-use energy efficiency). These important dynamics are discussed in more detail in the RIA in the rulemaking docket. The annualized incremental cost is the projected additional cost of complying with the guidelines in the year analyzed, and includes the amortized cost of capital investment, needed new capacity, shifts between or amongst various fuels, deployment of energy efficiency programs, and other actions associated with compliance. MRR costs are estimated to be $68.3 million (2011$) in 2020 and $8.9 million in 2025 and 2030 for Option 1 and $68.3 million in 2020 and $8.9 million in 2025 for Option 2. More detailed cost estimates are available in the RIA included in the rulemaking docket.

F. What are the economic and employment impacts?

The proposed standards are projected to result in certain changes to power system operation as a result of the application of state emission rate goals. Overall, we project dispatch changes, changes to fossil fuel and retail electricity prices, and some additional coal retirements. Average electric power sector-delivered natural gas prices are projected to increase by roughly 9 to 12 percent in 2020 in Option 1, with negligible changes by 2030. Under Option 2, electric power sector natural gas prices are projected to increase by roughly 8 percent in 2020, on an average nationwide basis, and increase by 1 percent or less in 2025. The average delivered coal price to the power sector is projected to decrease by 16 to 17 percent in 2020 under Option 1, and decrease by roughly 14 percent under Option 2, on a nationwide average basis. Retail electricity prices are projected to increase 6 to 7 percent under Option 1 and increase by roughly 4 percent under Option 2, both in 2020 and on an average basis across the contiguous U.S. By 2030 under Option 1, electricity prices are projected to increase by about 3 percent. Under Option 1, the EPA projects 46 to 50 GW of additional coal-fired generation may be uneconomic to maintain and may be removed from operation by 2030. The EPA projects that under Option 2, 30 to 33 GW of additional coal-fired generation may be uneconomic to maintain and may be removed from operation by 2025.

It is important to note that the EPA's modeling does not necessarily account for all of the factors that may influence business decisions regarding future coal fired capacity. By 2025, the average age of the coal-fired fleet will be 49 years old and twenty percent of the fleet will be more than 60 years old. Many power companies already factor a carbon price into their long term capacity planning that would further influence business decisions to replace these aging assets with modern, and significantly cleaner generation.

The compliance modeling done to support the proposal assumes that overall electric demand will decrease significantly, as states ramp up programs that result in lower overall demand. End-use energy efficiency levels increase such that they achieve about an 11 percent reduction on overall electricity demand levels in 2030 for Option 1, and a reduction in overall electricity demand of approximately 6 percent reduction in 2025 for Option 2. In response, there are anticipated to be notable changes to costs, prices, and electricity generation in the power sector as more end-use efficiency is realized.

Changes in price or demand for electricity, natural gas, coal, can impact markets for goods and services produced by sectors that use these energy inputs in the production process or supply those sectors. Changes in cost of production may result in changes in price, changes in quantity produced, and changes in profitability of firms affected. The EPA recognizes that these guidelines provide significant flexibilities and states implementing the guidelines may choose to mitigate impacts to some markets outside the EGU sector. Similarly, demand for new generation or energy efficiency can result in shifts in production and profitability for firms that supply those goods and services, and the guidelines provide flexibility for states that may want to enhance demand for goods and services from those sectors.

Executive Order 13563 directs federal agencies to consider the effect of regulations on job creation and employment. According to the Executive Order, ''our regulatory system must protect public health, welfare, safety, and our environment while promoting economic growth, innovation, competitiveness, and job creation. It must be based on the best available science.'' (Executive Order 13563, 2011) Although standard benefit-cost analyses have not typically included a separate analysis of regulation-induced employment impacts, we typically conduct employment analyses. During periods of sustained high unemployment, employment impacts are of particular concern and questions may arise about their existence and magnitude.

States have the responsibility and flexibility to implement policies and practices for compliance with Proposed Electric Generating Unit Greenhouse Gas Existing Source Guidelines. Quantifying the associated employment impacts is complicated by the wide range of approaches that States may use. As such, the EPA's employment analysis includes projected employment impacts associated with illustrative compliance scenarios for these guidelines for the electric power industry, coal and natural gas production, and demand-side energy efficiency activities. These projections are derived, in part, from a detailed model of the electricity production sector used for this regulatory analysis, and U.S government data on employment and labor productivity. In the electricity, coal, and natural gas sectors, the EPA estimates that these guidelines could have an employment impact of roughly 25,900 to 28,000 job-years increase in 2020 for Option 1, state to regional compliance approach, respectively. For Option 2, the state and regional compliance approach estimates are 26,700 to 29,800 job-years increase in 2020. Demand-side energy efficiency employment impacts are approximately an increase of 78,800 jobs in 2020 for Option 1 and of 57,000 jobs for Option 2. By its nature, energy efficiency reduces overall demand for electric power. The EPA recognizes as more efficiency is built into the U.S. power system over time, lower fuel requirements may lead to fewer jobs in the coal and natural gas extraction sectors, as well as in EGU construction and operation than would otherwise have been expected. The EPA also recognizes the fact that, in many cases, employment gains and losses that might be attributable to this rule would be expected to affect different sets of people. Moreover, workers who lose jobs in these sectors may find employment elsewhere just as workers employed in new jobs in these sectors may have been previously employed elsewhere. Therefore, the employment estimates reported in these sectors may include workers previously employed elsewhere. This analysis also does not capture potential economy-wide impacts due to changes in prices (of fuel, electricity, labor, etc.). For these reasons, the numbers reported here should not be interpreted as a net national employment impact.

G. What are the benefits of the proposed goals?

Implementing the proposed standards will generate benefits by reducing emissions of CO_2 as well as criteria pollutants and their precursors, including SO_2, NO_X and directly emitted particles. SO_2 and NO_X are precursors to $PM_{2.5}$ (particles smaller than 2.5 microns), and NO_X is a precursor to ozone. The estimated benefits associated with these emission reductions are beyond those achieved by previous EPA rulemakings including the Mercury and Air Toxics Standards rule. The health and welfare benefits from reducing air pollution are considered co-benefits for these standards. For this rulemaking, we were only able to quantify the climate benefits from reduced emissions of CO_2 and the health co-benefits associated with reduced exposure to $PM_{2.5}$ and ozone. In summary, we estimate the total combined climate benefits and health co-benefits for Option 1 to be $33 billion to $54 billion in 2020 and $55 billion to $89 billion in 2030 assuming a regional compliance approach (2011 dollars at a 3-percent discount rate [model average]). If states comply using a state-specific compliance approach, these climate and health co-benefits estimates are estimated to be $35 to $57 billion in 2020 and $57 to $93 billion in 2030 (2011 dollars at a 3-percent discount rate [model average]). We also estimate the total combined climate benefits and health co-benefits for Option 2 to be $26 billion to $44 billion in 2020 and $36 billion to $59 billion in 2025 (regional compliance approach, 2011 dollars at a 3-percent discount rate [model average]). Assuming a state compliance approach, the total combined climate benefits and health co-benefits for Option 2 are estimated to be $27 billion to $45 billion in 2020 and $36 billion to $60 billion in 2025 (2011 dollars at a 3-percent discount rate [model average]). A summary of the emission reductions and monetized benefits estimated for this rule at all discount rates and additional analysis years is provided in Tables 12 through 17 of this preamble.

TABLE 12—SUMMARY OF THE MONETIZED GLOBAL CLIMATE BENEFITS FOR THE PROPOSED OPTION 1

[Billions of 2011 dollars][a]

2020	Discount rate (statistic)	Monetized climate benefits	
		Regional compliance	State compliance
CO_2 Reductions (million metric tons)		371	383
	5 percent (average SCC)	$4.7	$4.9
	3 percent (average SCC)	$17	$18
	2.5 percent (average SCC)	$25	$26
	3 percent (95th percentile SCC)	$51	$52
2025			
CO_2 Reductions (million metric tons)		501	506
	5 percent (average SCC)	$7.5	$7.6
	3 percent (average SCC)	$25	$25
	2.5 percent (average SCC)	$37	$37
	3 percent (95th percentile SCC)	$76	$77
2030			
CO_2 Reductions (million metric tons)		545	555
	5 percent (average SCC)	$9.3	$9.5
	3 percent (average SCC)	$30	$31
	2.5 percent (average SCC)	$44	$44
	3 percent (95th percentile SCC)	$92	$94

[a] Climate benefit estimates reflect impacts from CO_2 emission changes in the analysis years presented in the table and do not account for changes in non-CO_2 GHG emissions. These estimates are based on the global social cost of carbon (SCC) estimates for the analysis years (2020, 2025, and 2030) and are rounded to two significant figures.

TABLE 13—SUMMARY OF THE MONETIZED GLOBAL CLIMATE BENEFITS FOR THE OPTION 2

[Billions of 2011 dollars][a]

2020	Discount rate (statistic)	Monetized climate benefits	
		Regional compliance	State compliance
CO_2 Reductions (million metric tons)		283	295
	5 percent (average SCC)	$3.6	$3.8
	3 percent (average SCC)	$13	$14
	2.5 percent (average SCC)	$19	$20
	3 percent (95th percentile SCC)	$39	$40
2025			
CO_2 Reductions (million metric tons)		368	376
	5 percent (average SCC)	$5.5	$5.6
	3 percent (average SCC)	$18	$19

TABLE 13—SUMMARY OF THE MONETIZED GLOBAL CLIMATE BENEFITS FOR THE OPTION 2—Continued

[Billions of 2011 dollars] [a]

2020	Discount rate (statistic)	Monetized climate benefits	
		Regional compliance	State compliance
	2.5 percent (average SCC)	$27	$28
	3 percent (95th percentile SCC)	$56	$57

[a] Climate benefit estimates reflect impacts from CO_2 emission changes in the analysis years presented in the table and do not account for changes in non-CO_2 GHG emissions. These estimates are based on the global SCC estimates for the analysis years (2020, 2025, and 2030) and are rounded to two significant figures.

TABLE 14—SUMMARY OF THE MONETIZED HEALTH CO-BENEFITS FOR THE PROPOSED STANDARDS OPTION 1 REGIONAL COMPLIANCE APPROACH IN THE U.S.

[Billions of 2011 dollars] [a]

Pollutant	National emission reductions (thousands of short tons)	Monetized health co-benefits (3 percent discount)	Monetized health co-benefits (7 percent discount)
Option 1 Regional Compliance Approach 2020			
$PM_{2.5}$ precursors: [b]			
SO_2	292	$12 to $26	$11 to $24
Directly emitted $PM_{2.5}$ (Elemental Carbon and Organic Carbon)	6	$0.75 to $1.7	$0.67 to $1.5
Directly emitted $PM_{2.5}$ (crustal)	44	$0.77 to $1.7	$0.69 to $1.6
NO_X	345	$2.2 to $5.0	$2.0 to $4.5
Ozone precursor: [c]			
NO_X (ozone season only)	146	$0.63 to $2.7	$0.63 to $2.7
Total Monetized Health Co-benefits		$16 to $37	$15 to $34
Total Monetized Health Co-benefits combined with Monetized Climate Benefits [d]		$33 to $54	$32 to $51
Option 1 Regional Compliance Approach 2025			
$PM_{2.5}$ precursors [b]			
SO_2	395	$17 to $38	$15 to $35
Directly emitted $PM_{2.5}$ (Elemental Carbon and Organic Carbon)	6	$0.85 to $1.9	$0.76 to $1.7
Directly emitted $PM_{2.5}$ (crustal)	46	$0.78 to $1.8	$0.70 to $1.6
NO_X	421	$3.0 to $6.8	$2.7 to $6.1
Ozone precursor: [c]			
NO_X (ozone season only)	180	$1.0 to $4.3	$1.0 to $4.3
Total Monetized Health Co-benefits		$23 to $53	$21 to $48
Total Monetized Health Co-benefits combined with Monetized Climate Benefits [d]		$48 to $78	$46 to $74
Option 1 Regional Compliance Approach 2030			
$PM_{2.5}$ precursors: [b]			
SO_2	424	$20 to $44	$18 to $40
Directly emitted $PM_{2.5}$ (Elemental Carbon and Organic Carbon)	5	$0.84 to $1.9	$0.76 to $1.7
Directly emitted $PM_{2.5}$ (crustal)	42	$0.77 to $1.7	$0.70 to $1.6
NO_X	407	$3.0 to $6.7	$2.7 to $6.1
Ozone precursor: [c]			
NO_X(ozone season only)	176	$1.1 to $4.5	$1.1 to $4.5
Total Monetized Health Co-benefits		$25 to $59	$23 to $54
Total Monetized Health Co-benefits combined with Monetized Climate Benefits [d]		$55 to $89	$53 to $84

[a] All estimates are for the analysis years (2020, 2025, 2030) and are rounded to two significant figures, so estimates may not sum. It is important to note that the monetized co-benefits do not include reduced health effects from direct exposure to SO_2, direct exposure to NO_2, ecosystem effects or visibility impairment. Air pollution health co-benefits are estimated using regional benefit-per-ton estimates for the contiguous U.S.

[b] The monetized $PM_{2.5}$ co-benefits reflect the human health benefits associated with reducing exposure to $PM_{2.5}$ through reductions of $PM_{2.5}$ precursors, such as SO_2, NO_X and directly emitted $PM_{2.5}$. PM co-benefits are shown as a range reflecting the use of two concentration-response functions, with the lower end of the range based on a function from Krewski et al. (2009) and the upper end based on a function from Lepeule et al. (2012). These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because the scientific evidence is not yet sufficient to allow differentiation of effect estimates by particle type.

[c] The monetized ozone co-benefits reflect the human health benefits associated with reducing exposure to ozone through reductions of NO_X during the ozone season. Ozone co-benefits are shown as a range reflecting the use of several different concentration-response functions, with the lower end of the range based on a function from Bell, et al. (2004) and the upper end based on a function from Levy, et al. (2005). Ozone co-benefits occur in the analysis year, so they are the same for all discount rates.

[d] We estimate climate benefits associated with four different values of a one ton CO_2 reduction (model average at 2.5 percent discount rate, 3 percent, and 5 percent; 95th percentile at 3 percent), which each increase over time. For the purposes of this table, we show the benefits associated with the model average at 3% discount rate, however we emphasize the importance and value of considering the full range of SCC values. We provide combined climate and health estimates based on additional discount rates in the RIA.

TABLE 15—SUMMARY OF THE MONETIZED HEALTH CO-BENEFITS IN THE U.S. FOR THE PROPOSED GUIDELINES OPTION 1 STATE COMPLIANCE APPROACH

[Billions of 2011 dollars] [a]

Pollutant	National emission reductions (thousands of short tons)	Monetized health co-benefits (3 percent discount)	Monetized health co-benefits (7 percent discount)
Option 1 State Compliance Approach in 2020			
$PM_{2.5}$ precursors: [b]			
SO_2	335	$13 to $29	$11 to $26
Directly emitted $PM_{2.5}$ (Elemental Carbon and Organic Carbon)	6	$0.76 to $1.7	$0.69 to $1.6
Directly emitted $PM_{2.5}$ (crustal)	45	$0.79 to $1.8	$0.71 to $1.6
NO_X	367	$2.2 to $4.9	$2.0 to $4.4
Ozone precursor: [c]			
NO_X (ozone season only)	157	$0.64 to $2.7	$0.64 to $2.7
Total Monetized Health Co-benefits		$17 to $40	$15 to $36
Total Monetized Health Co-benefits combined with Monetized Climate Benefits [d]		$35 to $57	$33 to $54
Option 1 State Compliance Approach in 2025			
$PM_{2.5}$ precursors: [b]			
SO_2	425	$18 to $40	$16 to $36
Directly emitted $PM_{2.5}$ (Elemental Carbon and Organic Carbon)	6	$0.90 to $2.0	$0.81 to $1.8
Directly emitted $PM_{2.5}$ (crustal)	49	$0.83 to $1.9	$0.75 to $1.7
NO_X	436	$2.9 to $6.5	$2.6 to $5.8
Ozone precursor: [c]			
NO_X (ozone season only)	190	$1.0 to $4.4	$1.0 to $4.4
Total Monetized Health Co-benefits		$23 to $54	$21 to $49
Total Monetized Health Co-benefits combined with Monetized Climate Benefits [d]		$49 to $80	$46 to $75
Option 1 State Compliance Approach in 2030			
$PM_{2.5}$ precursors: [b]			
SO_2	471	$21 to $47	$19 to $43
Directly emitted $PM_{2.5}$ (Elemental Carbon and Organic Carbon)	6	$0.87 to $2.0	$0.78 to $1.8
Directly emitted $PM_{2.5}$ (crustal)	44	$0.80 to $1.8	$0.72 to $1.6
NO_X	428	$2.9 to $6.6	$2.6 to $6.0
Ozone precursor: [c]			
NO_X (ozone season only)	187	$1.1 to $4.6	$1.1 to $4.6
Total Monetized Health Co-benefits		$27 to $62	$24 to $57
Total Monetized Health Co-benefits combined with Monetized Climate Benefits [d]		$57 to $93	$55 to $87

[a] All estimates are for the analysis years (2020, 2025, 2030) and are rounded to two significant figures, so estimates may not sum. It is important to note that the monetized co-benefits do not include reduced health effects from direct exposure to SO_2, direct exposure to NO_2, ecosystem effects or visibility impairment. Air pollution health co-benefits are estimated using regional benefit-per-ton estimates for the contiguous U.S.

[b] The monetized $PM_{2.5}$ co-benefits reflect the human health benefits associated with reducing exposure to $PM_{2.5}$ through reductions of $PM_{2.5}$ precursors, such as SO_2, NO_X and directly emitted $PM_{2.5}$. PM co-benefits are shown as a range reflecting the use of two concentration-response functions, with the lower end of the range based on a function from Krewski et al. (2009) and the upper end based on a function from Lepeule et al. (2012). These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because the scientific evidence is not yet sufficient to allow differentiation of effect estimates by particle type.

[c] The monetized ozone co-benefits reflect the human health benefits associated with reducing exposure to ozone through reductions of NO_X during the ozone season. Ozone co-benefits are shown as a range reflecting the use of several different concentration-response functions, with the lower end of the range based on a function from Bell, et al. (2004) and the upper end based on a function from Levy, et al. (2005). Ozone co-benefits occur in the analysis year, so they are the same for all discount rates.

[d] We estimate climate benefits associated with four different values of a one ton CO_2 reduction (model average at 2.5 percent discount rate, 3 percent, and 5 percent; 95th percentile at 3 percent), which each increase over time. For the purposes of this table, we show the benefits associated with the model average at 3% discount rate, however we emphasize the importance and value of considering the full range of SCC values. We provide combined climate and health estimates based on additional discount rates in the RIA.

TABLE 16—SUMMARY OF THE MONETIZED HEALTH CO-BENEFITS IN THE U.S. FOR THE OPTION 2 REGIONAL COMPLIANCE APPROACH

[Billions of 2011 dollars] [a]

Pollutant	National emission reductions (thousands of short tons)	Monetized health co-benefits (3 percent discount)	Monetized health co-benefits (7 percent discount)
Option 2 Regional Compliance Approach 2020			
$PM_{2.5}$ precursors: [b]			
SO_2	244	$9.8 to $22	$8.9 to $20
Directly emitted $PM_{2.5}$ (Elemental Carbon and Organic Carbon)	5	$0.61 to $1.4	$0.55 to $1.2
Directly emitted $PM_{2.5}$ (crustal)	36	$0.63 to $1.4	$0.57 to $1.3
NO_X	268	$1.7 to $3.9	$1.6 to $3.5
Ozone precursor: [c]			

TABLE 16—SUMMARY OF THE MONETIZED HEALTH CO-BENEFITS IN THE U.S. FOR THE OPTION 2 REGIONAL COMPLIANCE APPROACH—Continued

[Billions of 2011 dollars] [a]

Pollutant	National emission reductions (thousands of short tons)	Monetized health co-benefits (3 percent discount)	Monetized health co-benefits (7 percent discount)
NO_X (ozone season only)	111	$0.47 to $2.0	$0.47 to $2.0
Total Monetized Health Co-benefits		$13 to $31	$12 to $28
Total Monetized Health Co-benefits combined with Monetized Climate Benefits [d]		$26 to $44	$25 to $41
Option 2 Regional Compliance Approach in 2025			
$PM_{2.5}$ precursors: [b]			
SO_2	297	$13 to $29	$12 to $26
Directly emitted $PM_{2.5}$ (Elemental Carbon and Organic Carbon)	4	$0.64 to $1.4	$0.58 to $1.3
Directly emitted $PM_{2.5}$ (crustal)	34	$0.59 to $1.3	$0.53 to $1.2
NO_X	309	$2.2 to $5.0	$2.0 to $4.5
Ozone precursor: [c]			
NO_X (ozone season only)	129	$0.73 to $3.1	$0.73 to $3.1
Total Monetized Health Co-benefits		$17 to $40	$16 to $36
Total Monetized Health Co-benefits combined with Monetized Climate Benefits [d]		$36 to $59	$34 to $55

[a] All estimates are for the analysis years (2020, 2025) and are rounded to two significant figures, so estimates may not sum. It is important to note that the monetized co-benefits do not include reduced health effects from direct exposure to SO_2, direct exposure to NO_2, ecosystem effects or visibility impairment. Air pollution health co-benefits are estimated using regional benefit-per-ton estimates for the contiguous U.S.

[b] The monetized $PM_{2.5}$ co-benefits reflect the human health benefits associated with reducing exposure to $PM_{2.5}$ through reductions of $PM_{2.5}$ precursors, such as SO_2, NO_X and directly emitted $PM_{2.5}$. PM co-benefits are shown as a range reflecting the use of two concentration-response functions, with the lower end of the range based on a function from Krewski et al. (2009) and the upper end based on a function from Lepeule et al. (2012). These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because the scientific evidence is not yet sufficient to allow differentiation of effect estimates by particle type.

[c] The monetized ozone co-benefits reflect the human health benefits associated with reducing exposure to ozone through reductions of NO_X during the ozone season. Ozone co-benefits are shown as a range reflecting the use of several different concentration-response functions, with the lower end of the range based on a function from Bell, et al. (2004) and the upper end based on a function from Levy, et al. (2005). Ozone co-benefits occur in the analysis year, so they are the same for all discount rates.

[d] We estimate climate benefits associated with four different values of a one ton CO_2 reduction (model average at 2.5 percent discount rate, 3 percent, and 5 percent; 95th percentile at 3 percent), which each increase over time. For the purposes of this table, we show the benefits associated with the model average at 3% discount rate, however we emphasize the importance and value of considering the full range of SCC values. We provide combined climate and health estimates based on additional discount rates in the RIA.

TABLE 17—SUMMARY OF THE MONETIZED HEALTH CO-BENEFITS IN THE U.S. FOR OPTION 2 STATE COMPLIANCE APPROACH

[Billions of 2011 dollars] [a]

Pollutant	National emission reductions (thousands of short tons)	Monetized health co-benefits (3 percent discount)	Monetized health co-benefits (7 percent discount)
Option 2 State Compliance Approach in 2020			
$PM_{2.5}$ precursors: [b]			
SO_2	267	$10 to $23	$9.1 to $21
Directly emitted $PM_{2.5}$ (Elemental Carbon and Organic Carbon).	5	$0.64 to $1.5	$0.58 to $1.3
Directly emitted $PM_{2.5}$ (crustal)	38	$0.66 to $1.5	$0.60 to $1.4
NO_X	281	$1.7 to $3.8	$1.5 to $3.4
Ozone precursor: [c]			
NO_X (ozone season only)	119	$0.48 to $2.1	$0.48 to $2.1
Total Monetized Health Co-benefits		$14 to $32	$12 to $29
Total Monetized Health Co-benefits combined with Monetized Climate Benefits [d].		$27 to $45	$26 to $42
Option 2 State Compliance Approach in 2025			
$PM_{2.5}$ precursors: [b]			
SO_2	327	$14 to $30	$12 to $27
Directly emitted $PM_{2.5}$ (Elemental Carbon and Organic Carbon).	5	$0.69 to $1.6	$0.63 to $1.4
Directly emitted $PM_{2.5}$ (crustal)	38	$0.64 to $1.4	$0.58 to $1.3
NO_X	317	$2.1 to $4.7	$1.9 to $4.2
Ozone precursor: [c]			

TABLE 17—SUMMARY OF THE MONETIZED HEALTH CO-BENEFITS IN THE U.S. FOR OPTION 2 STATE COMPLIANCE APPROACH—Continued

[Billions of 2011 dollars] [a]

Pollutant	National emission reductions (thousands of short tons)	Monetized health co-benefits (3 percent discount)	Monetized health co-benefits (7 percent discount)
NO_X (ozone season only)	136	\$0.72 to \$3.1	\$0.72 to \$3.1
Total Monetized Health Co-benefits		\$18 to \$41	\$16 to \$16
Total Monetized Health Co-benefits combined with Monetized Climate Benefits [d].		\$36 to \$60	\$35 to \$56

[a] All estimates are for the analysis years (2020, 2025) and are rounded to two significant figures, so estimates may not sum. It is important to note that the monetized co-benefits do not include reduced health effects from direct exposure to SO_2, direct exposure to NO_2, ecosystem effects or visibility impairment. Air pollution health co-benefits are estimated using regional benefit-per-ton estimates for the contiguous U.S.

[b] The monetized $PM_{2.5}$ co-benefits reflect the human health benefits associated with reducing exposure to $PM_{2.5}$ through reductions of $PM_{2.5}$ precursors, such as SO_2, NO_X and directly emitted $PM_{2.5}$. PM co-benefits are shown as a range reflecting the use of two concentration-response functions, with the lower end of the range based on a function from Krewski et al. (2009) and the upper end based on a function from Lepeule et al. (2012). These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because the scientific evidence is not yet sufficient to allow differentiation of effect estimates by particle type.

[c] The monetized ozone co-benefits reflect the human health benefits associated with reducing exposure to ozone through reductions of NO_X during the ozone season. Ozone co-benefits are shown as a range reflecting the use of several different concentration-response functions, with the lower end of the range based on a function from Bell, et al. (2004) and the upper end based on a function from Levy, et al. (2005). Ozone co-benefits occur in the analysis year, so they are the same for all discount rates.

[d] We estimate climate benefits associated with four different values of a one ton CO_2 reduction (model average at 2.5 percent discount rate, 3 percent, and 5 percent; 95th percentile at 3 percent), which each increase over time. For the purposes of this table, we show the benefits associated with the model average at 3% discount rate; however, we emphasize the importance and value of considering the full range of SCC values. We provide combined climate and health estimates based on additional discount rates in the RIA.

The EPA has used the social cost of carbon (SCC) estimates presented in the 2013 *Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866* (2013 SCC TSD) to analyze CO_2 climate impacts of this rulemaking.[331] We refer to these estimates, which were developed by the U.S. government, as ''SCC estimates.'' The U.S. government first published the SCC estimates in 2010 following an interagency process that included the EPA and other executive branch entities; the process used three integrated assessment models (IAM) to develop SCC estimates and selected four global values for use in regulatory analyses. The U.S. government recently updated these estimates using new versions of each integrated assessment model and published them in 2013. The 2013 update did not revisit the 2010 modeling decisions (e.g., with regard to the discount rate, reference case socioeconomic and emission scenarios or equilibrium climate sensitivity). Rather, improvements in the way damages are modeled are confined to those that have been incorporated into the latest versions of the models by the developers themselves and published in the peer-reviewed literature. The 2010 SCC Technical Support Document (2010 SCC TSD) provides a complete discussion of the methods used to develop these estimates and the 2013 SCC TSD presents and discusses the updated estimates.[332]

The EPA and other agencies have sought public comment on the SCC estimates as part of various rulemakings. In addition, OMB's Office of Information and Regulatory Affairs recently sought public comment on the approach used to develop the estimates. The comment period ended on February 26, 2014, and OMB is reviewing the comments received.

The four SCC estimates, updated in 2013, are as follows: \$13, \$46, \$68, and \$137 per metric ton of CO_2 emissions in the year 2020 (2011 dollars).[333] The first three values are based on the average SCC from the three IAMs, at discount rates of 5, 3, and 2.5 percent, respectively. SCCs at several discount rates are included because the literature shows that the SCC is quite sensitive to assumptions about the discount rate, and because no consensus exists on the appropriate rate to use in an intergenerational context (where costs and benefits are incurred by different generations). The fourth value is the 95th percentile of the SCC from all three models at a 3 percent discount rate. It is included to represent higher-than-expected impacts from temperature change further out in the tails of the SCC distribution (representing less likely, but potentially catastrophic, outcomes).

The 2010 SCC TSD noted a number of limitations to the SCC analysis, including the incomplete way in which the integrated assessment models capture catastrophic and non-catastrophic impacts, their incomplete treatment of adaptation and

[331] Docket ID EPA–HQ–OAR–2013–0495, Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866, Interagency Working Group on Social Cost of Carbon, with participation by Council of Economic Advisers, Council on Environmental Quality, Department of Agriculture, Department of Commerce, Department of Energy, Department of Transportation, Environmental Protection Agency, National Economic Council, Office of Energy and Climate Change, Office of Management and Budget, Office of Science and Technology Policy, and Department of Treasury (May 2013, Revised November 2013). Available at: *http://www.whitehouse.gov/sites/default/files/omb/assets/inforeg/technical-update-social-cost-of-carbon-for-regulator-impact-analysis.pdf.*

[332] Docket ID EPA–HQ–OAR–2009–0472–114577, *Technical Support Document: Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866, Interagency Working Group on Social Cost of Carbon,* with participation by the Council of Economic Advisers, Council on Environmental Quality, Department of Agriculture, Department of Commerce, Department of Energy, Department of Transportation, Environmental Protection Agency, National Economic Council, Office of Energy and Climate Change, Office of Management and Budget, Office of Science and Technology Policy, and Department of Treasury (February 2010). Also available at: *http://www.whitehouse.gov/sites/default/files/omb/inforeg/for-agencies/Social-Cost-of-Carbon-for-RIA.pdf*>.

[333] The 2010 and 2013 TSDs present SCC in \$2007. The estimates were adjusted to 2011\$ using the GDP Implicit Price Deflator. Also available at: *http://www.gpo.gov/fdsys/pkg/ECONI-2013-02/pdf/ECONI-2013-02-Pg3.pdf.*

technological change, uncertainty in the extrapolation of damages to high temperatures, and assumptions regarding risk aversion. Current integrated assessment models do not assign value to all of the important physical, ecological, and economic impacts of climate change recognized in the climate change literature for various reasons, including the inherent difficulties in valuing non-market impacts and the fact that the science incorporated into these models understandably lags behind the most recent research. Nonetheless, these estimates and the discussion of their limitations represent the best available information about the social benefits of CO_2 emission reductions to inform the benefit-cost analysis. Model developers continually update the models to incorporate recent research. The new versions of the models used to estimate the values presented in this rulemaking offer some improvements in these areas identified above, although further work is warranted. Accordingly, the EPA and other parties continue to conduct research on modeling and valuation of climate impacts with the goal of improving these estimates. Additional details are provided in the SCC TSDs.

The health co-benefits estimates represent the total monetized human health benefits for populations exposed to reduced $PM_{2.5}$ and ozone resulting from emission reductions under illustrative compliance options for the proposed standards. Unlike the global SCC estimates, the air pollution health co-benefits are estimated for the contiguous U.S. only. We used a ''benefit-per-ton'' approach to estimate the benefits of this rulemaking. To create the $PM_{2.5}$ benefit-per-ton estimates, this approach uses a model to convert emissions of $PM_{2.5}$ precursors into changes in ambient $PM_{2.5}$ levels and another model to estimate the changes in human health effects associated with that change in air quality, which are then divided by the emissions in specific sectors. We derived national average benefit-per-ton estimates for the EGU sector using the approach published in Fann et al. (2012),[334] and updated those estimates to reflect the studies and population data in the 2012 PM NAAQS RIA. We further separated the national estimates into regional estimates to provide greater spatial resolution.[335] In addition, we generated regional benefit-per-ton estimates for changes in ozone exposure. The ozone estimates used the ozone information from the sector modeling for the EGU sector described in Fann et al. (2012) and the health impact assumptions used in the Ozone NAAQS RIAs.[336] [337] To calculate the co-benefits for the proposed standards, we multiplied the regional benefit-per-ton estimates for the EGU sector by the corresponding emission reductions.[338] All benefit-per-ton estimates reflect the geographic distribution of the modeled emissions, which may not exactly match the emission reductions in this rulemaking, and thus they may not reflect the local variability in population density, meteorology, exposure, baseline health incidence rates, or other local factors for any specific location. More information regarding the derivation of the benefit-per-ton estimates is available in the RIA.

These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because the scientific evidence is not yet sufficient to allow differentiation of effect estimates by particle type. Even though we assume that all fine particles have equivalent health effects, the benefit-per-ton estimates vary between precursors depending on the location and magnitude of their impact on $PM_{2.5}$ levels, which drive population exposure.

It is important to note that the magnitude of the $PM_{2.5}$ and ozone co-benefits is largely driven by the concentration response functions for premature mortality and the value of a statistical life used to value reductions in premature mortality. For $PM_{2.5}$, we cite two key empirical studies, one based on the American Cancer Society cohort study[339] and the extended Six Cities cohort study.[340] We present the $PM_{2.5}$ co-benefits results as a range based on the concentration-response functions from these two epidemiology studies, but this range does not capture the full range of uncertainty inherent in the co-benefits estimates. In the RIA for this rule, which is available in the docket, we also include $PM_{2.5}$ co-benefits estimates derived from expert judgments (Roman et al., 2008)[341] as a characterization of uncertainty regarding the $PM_{2.5}$-mortality relationship. For the ozone co-benefits, we present the results as a range reflecting the use of several different concentration-response functions for mortality, with the lower end of the range based on a function from Bell et al. (2004)[342] and the upper end based on a function from Levy et al. (2005).[343] Similar to $PM_{2.5}$, the range of ozone co-benefits does not capture the full range of inherent uncertainty.

In this analysis, the EPA assumes that the health impact function for fine particles is without a threshold. This is based on the conclusions of EPA's *Integrated Science Assessment for Particulate Matter,*[344] which evaluated the substantial body of published scientific literature, reflecting thousands of epidemiology, toxicology, and clinical studies that documents the association between elevated $PM_{2.5}$

[334] Fann, N., K.R. Baker and C.M. Fulcher. 2012. ''Characterizing the $PM_{2.5}$-related health benefits of emission reductions for 17 industrial, area and mobile emission sectors across the U.S.'' *Environment International* 49 41–151.

[335] U.S. Environmental Protection Agency (U.S. EPA). 2012. *Regulatory Impact Analysis for the Final Revisions to the National Ambient Air Quality Standards for Particulate Matter.* Research Triangle Park, NC: Office of Air Quality Planning and Standards, Health and Environmental Impacts Division. (EPA document number EPA–452/R–12–003, December). Available at: <*http://www.epa.gov/pm/2012/finalria.pdf*>.

[336] U.S. Environmental Protection Agency (U.S. EPA). 2008b. *Final Ozone NAAQS Regulatory Impact Analysis.* Research Triangle Park, NC: Office of Air Quality Planning and Standards, Health and Environmental Impacts Division, Air Benefit and Cost Group Research. (EPA document number EPA–452/R–08–003, March). Available at: <*http://cfpub.epa.gov/ncea/cfm/recordisplay.cfm?deid=194645*>.

[337] U.S. Environmental Protection Agency (U.S. EPA). 2010. *Section 3: Re-analysis of the Benefits of Attaining Alternative Ozone Standards to Incorporate Current Methods.* Available at <*http://www.epa.gov/ttnecas1/regdata/RIAs/s3-supplemental_analysis-updated_benefits11-5.09.pdf*>.

[338] U.S. Environmental Protection Agency. 2013. *Technical support document: Estimating the benefit per ton of reducing $PM_{2.5}$ precursors from 17 sectors.* Research Triangle Park, NC: Office of Air and Radiation, Office of Air Quality Planning and Standards, January. Available at: <*http://www.epa.gov/airquality/benmap/models/Source_Apportionment_BPT_TSD_1_31_13.pdf*>.

[339] Krewski D.; M. Jerrett; R.T. Burnett; R. Ma; E. Hughes; Y. Shi, et al. 2009. *Extended Follow-up and Spatial Analysis of the American Cancer Society Study Linking Particulate Air Pollution and Mortality.* Health Effects Institute. (HEI Research Report number 140). Boston, MA: Health Effects Institute.

[340] Lepeule, J.; F. Laden; D. Dockery; J. Schwartz. 2012. ''Chronic Exposure to Fine Particles and Mortality: An Extended Follow-Up of the Harvard Six Cities Study from 1974 to 2009.'' *Environmental Health Perspective,* 120(7), July, pp. 965–970.

[341] Roman, H., et al. 2008. ''Expert Judgment Assessment of the Mortality Impact of Changes in Ambient Fine Particulate Matter in the U.S.'' *Environmental Science & Technology,* Vol. 42, No. 7, February, pp. 2268–2274.

[342] Bell, M.L., et al. 2004. ''Ozone and Short-Term Mortality in 95 U.S. Urban Communities, 1987–2000.'' *Journal of the American Medical Association,* 292(19), pp. 2372–8.

[343] Levy, J.I., S.M. Chemerynski, and J.A. Sarnat. 2005. ''Ozone exposure and mortality: an empiric bayes metaregression analysis.'' *Epidemiology.* 16(4): p. 458–68.

[344] U.S. Environmental Protection Agency. 2009. *Integrated Science Assessment for Particulate Matter (Final Report).* Research Triangle Park, NC: National Center for Environmental Assessment, RTP Division. (EPA document number EPA–600–R–08–139F, December). Available at: <*http://cfpub.epa.gov/ncea/cfm/recordisplay.cfm?deid=216546*>.

concentrations and adverse health effects, including increased premature mortality. This assessment, which was twice reviewed by the EPA's independent Science Advisory Board, concluded that the scientific literature consistently finds that a no-threshold model most adequately portrays the PM-mortality concentration-response relationship.

In general, we are more confident in the magnitude of the risks we estimate from simulated $PM_{2.5}$ concentrations that coincide with the bulk of the observed PM concentrations in the epidemiological studies that are used to estimate the benefits. Likewise, we are less confident in the risk we estimate from simulated $PM_{2.5}$ concentrations that fall below the bulk of the observed data in these studies.

For this analysis, policy-specific air quality data are not available,[345] and thus, we are unable to estimate the percentage of premature mortality associated with this specific rule's emission reductions at each $PM_{2.5}$ level. As a surrogate measure of mortality impacts, we provide the percentage of the population exposed above the lowest measured $PM_{2.5}$ level (LML) in each of the studies from which we obtained concentration-response functions for $PM_{2.5}$ mortality, using the estimates of $PM_{2.5}$ from the source apportionment modeling used to calculate the benefit-per-ton estimates for the EGU sector. Using the Krewski et al. (2009) study, 93 percent of the population is exposed to annual mean $PM_{2.5}$ levels at or above the LML of 5.8 micrograms per cubic meter (μg/m³). Using the Lepeule et al. (2012) study, 67 percent of the population is exposed above the LML of 8 μg/m³. It is important to note that baseline exposure is only one parameter in the health impact function, along with baseline incidence rates, population, and change in air quality. Therefore, caution is warranted when interpreting the LML assessment for this rule because these results are not consistent with results from rules that had air quality modeling.

Every benefit analysis examining the potential effects of a change in environmental protection requirements is limited, to some extent, by data gaps, model capabilities (such as geographic coverage) and uncertainties in the underlying scientific and economic studies used to configure the benefit and cost models. Despite these uncertainties, we believe the air quality co-benefit analysis for this rule provides a reasonable indication of the expected health benefits of the air pollution emission reductions for the illustrative compliance options for the proposed standards under a set of reasonable assumptions. This analysis does not include the type of detailed uncertainty assessment found in the 2012 $PM_{2.5}$ National Ambient Air Quality Standard (NAAQS) RIA (U.S. EPA, 2012) because we lack the necessary air quality input and monitoring data to conduct a complete benefits assessment. In addition, using a benefit-per-ton approach adds another important source of uncertainty to the benefits estimates. The 2012 $PM_{2.5}$ NAAQS benefits analysis provides an indication of the sensitivity of our results to various assumptions.

We note that the monetized co-benefits estimates shown here do not include several important benefit categories, including exposure to SO_2, NO_X, and hazardous air pollutants (e.g., mercury and hydrogen chloride), as well as ecosystem effects and visibility impairment. Although we do not have sufficient information or modeling available to provide monetized estimates for this rule, we include a qualitative assessment of these unquantified benefits in the RIA for these proposed amendments.

For more information on the benefits analysis, please refer to the RIA for this rule, which is available in the rulemaking docket.

XI. Statutory and Executive Order Reviews

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

Under Section 3(f)(1) of Executive Order 12866 (58 FR 51735, October 4, 1993), this action is an ''economically significant regulatory action'' because it is likely to have an annual effect on the economy of $100 million or more or adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or state, local, or tribal governments or communities. The $100 million threshold can be triggered by either costs or benefits, or a combination of them. Accordingly, the EPA submitted this action to OMB for review under Executive Orders 12866 and 13563 (76 FR 3821, January 21, 2011), and any changes made in response to OMB recommendations have been documented in the docket for this action.

The EPA also prepared an analysis of the potential costs and benefits associated with this action. This analysis is contained in the RIA for this proposed rule. A copy of the analysis is available in the docket for this action.

Consistent with EO 12866 and EO 13563, the EPA estimated the costs and benefits for illustrative compliance approaches of implementing the proposed guidelines. This proposal sets goals to reduce CO_2 emissions from the electric power industry. Actions taken to comply with the proposed guidelines will also reduce the emissions of directly emitted $PM_{2.5}$, sulfur dioxide (SO_2) and nitrogen oxides (NO_X). The benefits associated with these PM, SO_2 and NO_X reductions are referred to as co-benefits, as these reductions are not the primary objective of this rule.

The EPA has used the social cost of carbon estimates presented in the 2013 *Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866* (2013 SCC TSD) to analyze CO_2 climate impacts of this rulemaking. We refer to these estimates, which were developed by the U.S. government, as ''SCC estimates.'' The SCC is an estimate of the monetary value of impacts associated with a marginal change in CO_2 emissions in a given year. The four SCC estimates are associated with different discount rates (model average at 2.5 percent discount rate, 3 percent, and 5 percent; 95th percentile at 3 percent), and each increases over time. In this summary, the EPA provides the estimate of climate benefits associated with the SCC value deemed to be central in the SCC TSD: The model average at 3% discount rate. For the regional compliance approach, the EPA estimates that in 2020 this Option 1 proposal will yield monetized climate benefits (in 2011$) of approximately $17 billion (3 percent model average). The air pollution health co-benefits in 2020 are estimated to be $16 billion to $37 billion (2011$) for a 3 percent discount rate and $15 billion to $34 billion (2011$) for a 7 percent discount rate. The annual, illustrative compliance costs estimated by IPM and inclusive of demand side energy efficiency program and participant costs and MRR costs, are approximately $5.5 billion (2011$) in 2020. The quantified net benefits (the difference between monetized benefits and costs) in 2020 are estimated to be $28 billion to $49 billion assuming a regional compliance approach (2011$) using a 3 percent discount rate (model average). This range of net benefits is estimated to be $27 billion to $50 billion assuming a state compliance approach (2011$)

[345] In addition, site-specific emission reductions will depend upon how states implement the guidelines.

using a 3 percent discount rate (model average). Table 18 shows the climate benefits, health co-benefits, cost and net benefits for Option 1 in 2020 for state and regional compliance approaches. Table 19 shows similar estimates for 2030.

For Option 1 in 2030 assuming a regional compliance approach, the EPA estimates this proposal will yield monetized climate benefits (in 2011$) of approximately $30 billion (3 percent, model average). The air pollution health co-benefits in 2030 are estimated to be $25 billion to $59 billion (2011$) for a 3 percent discount rate and $23 billion to $54 billion (2011$) for a 7 percent discount rate. The annual illustrative compliance costs estimated using IPM, inclusive of a demand-side energy efficiency program and participant costs and MRR costs, are approximately $7.3 billion (2011$) in 2030. The quantified net benefits (the difference between monetized benefits and costs) in 2030 are estimated to be $48 billion to $82 billion (2011$) using a 3 percent discount rate (model average). The EPA estimates that this proposal will yield monetized climate benefits (in 2011$) of approximately $31 billion (3 percent, model average) for Option 1 state compliance approach in 2030. The air pollution health co-benefits in 2030 are estimated to be $27 billion to $62 billion (2011$) for a 3 percent discount rate and $24 billion to $56 billion (2011$) for a 7 percent discount rate. The annual illustrative compliance costs estimated using IPM, inclusive of demand side energy efficiency program and participant costs and MRR costs, are approximately $8.8 billion (2011$) in 2030. The quantified net benefits (the difference between monetized benefits and costs) in 2030 are estimated to be $49 billion to $84 billion (2011$) using a 3 percent discount rate (model average) assuming a state compliance approach. Based upon the foregoing discussion, it remains clear that the benefits of the proposal Option 1 are substantial and far exceed the costs.

TABLE 18—SUMMARY OF THE MONETIZED BENEFITS, COMPLIANCE COSTS AND NET BENEFITS FOR PROPOSED OPTION 1 IN 2020 [a]

[Billions of 2011$]

	3% Discount rate	7% Discount rate
Option 1 Regional Compliance Approach		
Climate benefits [b]	$17.	
Air pollution health co-benefits [c]	$16 to $37	$15 to $34
Total Compliance Costs [d]	$5.5	$5.5
Net Monetized Benefits [e]	$28 to $49	$26 to $45
Non-monetized Benefits	Direct exposure to SO_2 and NO_2. 1.3 tons of Hg. Ecosystem Effects. Visibility impairment.	
Option 1 State Compliance Approach		
Climate benefits [b]	$18.	
Air pollution health co-benefits [c]	$17 to $40	$15 to $36
Total Compliance Costs [d]	$7.5	$7.5
Net Monetized Benefits [e]	$27 to $50	$26 to $46
Non-monetized Benefits	Direct exposure to SO_2 and NO_2. 1.5 tons of Hg. Ecosystem Effects. Visibility impairment.	

[a] All estimates are for 2020, and are rounded to two significant figures, so figures may not sum.

[b] The climate benefit estimate in this summary table reflects global impacts from CO_2 emission changes and does not account for changes in non-CO_2 GHG emissions. Also, different discount rates are applied to SCC than to the other estimates because CO_2 emissions are long-lived and subsequent damages occur over many years. The benefit estimates in this table are based on the average SCC estimated for a 3 percent discount rate; however, we emphasize the importance and value of considering the full range of SCC values. As shown in the RIA, climate benefits are also estimated using the other three SCC estimates (model average at 2.5 percent discount rate, 3 percent, and 5 percent; 95th percentile at 3 percent). The SCC estimates are year-specific and increase over time.

[c] The air pollution health co-benefits reflect reduced exposure to $PM_{2.5}$ and ozone associated with emission reductions of directly emitted $PM_{2.5}$, SO_2 and NO_X. The range reflects the use of concentration-response functions from different epidemiology studies. The reduction in premature fatalities each year accounts for over 90 percent of total monetized co-benefits from $PM_{2.5}$ and ozone. These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because the scientific evidence is not yet sufficient to allow differentiation of effect estimates by particle type.

[d] Total costs are approximated by the illustrative compliance costs estimated using the Integrated Planning Model for the proposed option and a discount rate of approximately 5 percent. This estimate includes monitoring, recordkeeping, and reporting costs and demand side energy efficiency program and participant costs.

[e] The estimates of net benefits in this summary table are calculated using the global social cost of carbon at a 3 percent discount rate (model average). The RIA includes combined climate and health estimates based on these additional discount rates.

TABLE 19—SUMMARY OF THE MONETIZED BENEFITS, COMPLIANCE COSTS, AND NET BENEFITS FOR PROPOSED OPTION 1 IN 2030 [a]

[Billions of 2011$]

	3% Discount rate	7% Discount rate
Option 1 Regional Compliance Approach		
Climate benefits [b]	$30.	
Air pollution health co-benefits [c]	$25 to $59	$23 to $54
Total Compliance Costs [d]	$7.3	$7.3
Net Monetized Benefits [e]	$48 to $82	$46 to $77

TABLE 19—SUMMARY OF THE MONETIZED BENEFITS, COMPLIANCE COSTS, AND NET BENEFITS FOR PROPOSED OPTION 1 IN 2030 [a]—Continued

[Billions of 2011$]

	3% Discount rate	7% Discount rate
Non-monetized Benefits	Direct exposure to SO_2 and NO_2. 1.7 tons of Hg and 580 tons of HCl. Ecosystem Effects. Visibility impairment.	
Option 1 State Compliance Approach		
Climate benefits [b]	$31.	
Air pollution health co-benefits [c]	$27 to $62	$24 to $56
Total Compliance Costs [d]	$8.8	$8.8
Net Monetized Benefits [e]	$49 to $84	$46 to $79
Non-monetized Benefits	Direct exposure to SO_2 and NO_2. 2.1 tons of Hg and 590 tons of HCl. Ecosystem Effects. Visibility impairment.	

[a] All estimates are for 2030, and are rounded to two significant figures, so figures may not sum.

[b] The climate benefit estimate in this summary table reflects global impacts from CO_2 emission changes and does not account for changes in non-CO_2 GHG emissions. Also, different discount rates are applied to SCC than to the other estimates because CO_2 emissions are long-lived and subsequent damages occur over many years. The benefit estimates in this table are based on the average SCC estimated for a 3 percent discount rate; however, we emphasize the importance and value of considering the full range of SCC values. As shown in the RIA, climate benefits are also estimated using the other three SCC estimates (model average at 2.5 percent discount rate, 3 percent, and 5 percent; 95th percentile at 3 percent). The SCC estimates are year-specific and increase over time.

[c] The air pollution health co-benefits reflect reduced exposure to $PM_{2.5}$ and ozone associated with emission reductions of directly emitted $PM_{2.5}$, SO_2 and NO_X. The range reflects the use of concentration-response functions from different epidemiology studies. The reduction in premature fatalities each year accounts for over 90 percent of total monetized co-benefits from $PM_{2.5}$ and ozone. These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because the scientific evidence is not yet sufficient to allow differentiation of effect estimates by particle type.

[d] Total costs are approximated by the illustrative compliance costs estimated using the Integrated Planning Model for the proposed option and a discount rate of approximately 5 percent. This estimate includes monitoring, recordkeeping, and reporting costs and demand side energy efficiency program and participant costs.

[e] The estimates of net benefits in this summary table are calculated using the global social cost of carbon at a 3 percent discount rate (model average). The RIA includes combined climate and health estimates based on these additional discount rates.

The estimated costs and benefits for the regulatory alternative—Option 2 regional and state compliance approaches are shown in Tables 20 and 21. As these tables reflect, net benefits in 2020 are estimated to be $22 to $40 billion (3 percent discount rate) and $21 to $37 billion (7 percent discount rate) for Option 2 assuming regional compliance. These Option 2 net benefit estimates become $22 to $40 billion (3 percent discount rate) and $20 to $37 billion (7 percent discount rate) with the state compliance approach. In 2025, net benefits are estimated to be $31 billion to $54 billion (3 percent discount rate) and $29 billion to $50 billion (7 percent discount rate) assuming a regional compliance approach and $31 billion to $55 billion (3 percent discount rate) and $29 billion to $51 billion (7 percent discount rate) assuming a state compliance approach.

The EPA could not monetize important benefits of proposed Option 1 and regulatory alternative Option 2. Unquantified benefits include climate benefits from reducing emissions of non-CO_2 greenhouse gases and co-benefits from reducing exposure to SO_2, NO_X, and hazardous air pollutants (e.g., mercury and hydrogen chloride), as well as ecosystem effects and visibility impairment.

TABLE 20—SUMMARY OF THE MONETIZED BENEFITS, COMPLIANCE COSTS, AND NET BENEFITS FOR PROPOSED OPTION 2 IN 2020 [a]

[Billions of 2011$]

	3% Discount rate	7% Discount rate
Option 2 Regional Compliance Approach		
Climate benefits [b]	$13.	
Air pollution health co-benefits [c]	$13 to $31	$12 to $28
Total Compliance Costs [d]	$4.3	$4.3
Net Monetized Benefits [e]	$22 to $40	$21 to $37
Non-monetized Benefits	Direct exposure to SO_2 and NO_2. 0.9 tons of Hg. Ecosystem Effects. Visibility impairment.	

TABLE 20—SUMMARY OF THE MONETIZED BENEFITS, COMPLIANCE COSTS, AND NET BENEFITS FOR PROPOSED OPTION 2 IN 2020 a—Continued

[Billions of 2011$]

	3% Discount rate	7% Discount rate
Option 2 State Compliance Approach		
Climate benefits [b]	$14.	
Air pollution health co-benefits [c]	$14 to $32	$12 to $29
Total Compliance Costs [d]	$5.5	$5.5
Net Monetized Benefits [e]	$22 to $40	$20 to $37
Non-monetized Benefits	Direct exposure to SO_2 and NO_2. 1.2 tons of Hg. Ecosystem Effects. Visibility impairment.	

[a] All estimates are for 2020, and are rounded to two significant figures, so figures may not sum.

[b] The climate benefit estimate in this summary table reflects global impacts from CO_2 emission changes and does not account for changes in non-CO_2 GHG emissions. Also, different discount rates are applied to SCC than to the other estimates because CO_2 emissions are long-lived and subsequent damages occur over many years. The benefit estimates in this table are based on the average SCC estimated for a 3 percent discount rate; however, we emphasize the importance and value of considering the full range of SCC values. As shown in the RIA, climate benefits are also estimated using the other three SCC estimates (model average at 2.5 percent discount rate, 3 percent, and 5 percent; 95th percentile at 3 percent). The SCC estimates are year-specific and increase over time.

[c] The air pollution health co-benefits reflect reduced exposure to $PM_{2.5}$ and ozone associated with emission reductions of directly emitted $PM_{2.5}$, SO_2 and NO_X. The range reflects the use of concentration-response functions from different epidemiology studies. The reduction in premature fatalities each year accounts for over 90 percent of total monetized co-benefits from $PM_{2.5}$ and ozone. These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because the scientific evidence is not yet sufficient to allow differentiation of effect estimates by particle type.

[d] Total costs are approximated by the illustrative compliance costs estimated using the Integrated Planning Model for the proposed option and a discount rate of approximately 5 percent. This estimate includes monitoring, recordkeeping and reporting costs and demand side energy efficiency program and participant costs.

[e] The estimates of net benefits in this summary table are calculated using the global social cost of carbon at a 3 percent discount rate (model average). The RIA includes combined climate and health estimates based on these additional discount rates.

TABLE 21—SUMMARY OF THE MONETIZED BENEFITS, COMPLIANCE COSTS, AND NET BENEFITS FOR PROPOSED OPTION 2 IN 2025 [a]

[Billions of 2011$]

	3% Discount rate	7% Discount rate
Option 2 Regional Compliance Approach		
Climate benefits [b]	$18.	
Air pollution health co-benefits [c]	$17 to $40	$16 to $36
Total Compliance Costs [d]	$4.5	$4.5
Net Monetized Benefits [e]	$31 to $54	$29 to $50
Non-monetized Benefits	Direct exposure to SO_2 and NO_2. 1.3 tons of Hg. Ecosystem Effects. Visibility impairment.	
Option 2 State Compliance Approach		
Climate benefits [b]	$19.	
Air pollution health co-benefits [c]	$18 to $41	$16 to $37
Total Compliance Costs [d]	$5.5	$5.5
Net Monetized Benefits [e]	$31 to $55	$29 to $51
Non-monetized Benefits	Direct exposure to SO_2 and NO_2. 1.7 tons of Hg. Ecosystem Effects. Visibility impairment.	

[a] All estimates are for 2025, and are rounded to two significant figures, so figures may not sum.

[b] The climate benefit estimate in this summary table reflects global impacts from CO_2 emission changes and does not account for changes in non-CO_2 GHG emissions. Also, different discount rates are applied to SCC than to the other estimates because CO_2 emissions are long-lived and subsequent damages occur over many years. The benefit estimates in this table are based on the average SCC estimated for a 3 percent discount rate; however, we emphasize the importance and value of considering the full range of SCC values. As shown in the RIA, climate benefits are also estimated using the other three SCC estimates (model average at 2.5 percent discount rate, 3 percent, and 5 percent; 95th percentile at 3 percent). The SCC estimates are year-specific and increase over time.

[c] The air pollution health co-benefits reflect reduced exposure to $PM_{2.5}$ and ozone associated with emission reductions of directly emitted $PM_{2.5}$, SO_2 and NO_X. The range reflects the use of concentration-response functions from different epidemiology studies. The reduction in premature fatalities each year accounts for over 90 percent of total monetized co-benefits from $PM_{2.5}$ and ozone. These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because the scientific evidence is not yet sufficient to allow differentiation of effect estimates by particle type.

[d] Total costs are approximated by the illustrative compliance costs estimated using the Integrated Planning Model for the proposed option and a discount rate of approximately 5 percent. This estimate includes monitoring, recordkeeping and reporting costs and demand side energy efficiency program and participant costs.

[e] The estimates of net benefits in this summary table are calculated using the global social cost of carbon at a 3 percent discount rate (model average). The RIA includes combined climate and health estimates based on these additional discount rates.

The analysis done in support of this proposal shows that the emission reductions, benefits, and costs for the illustrative compliance approaches for the proposed Option 1 (and regulatory alternative Option 2) are larger if states choose to comply on an individual basis, compared to the illustrative regional compliance approach. The regional approach allows for more flexibility across states, which results in slightly fewer emission reductions and lower overall costs. Net benefits (the difference between benefits and costs) are roughly equivalent under the regional and state compliance approaches.

In evaluating the impacts of the proposed guidelines, we analyzed a number of uncertainties, for example evaluating different potential spatial approaches to state compliance (i.e., state and regional) and in the estimated benefits of reducing carbon dioxide and other air pollutants. For a further discussion of key evaluations of uncertainty in the regulatory analyses for this proposed rulemaking, see the RIA included in the docket.

B. Paperwork Reduction Act

The information collection requirements in this proposed rule have been submitted for approval to the Office of Management and Budget (OMB) under the *Paperwork Reduction Act,* 44 U.S.C. 3501 *et seq.* The Information Collection Request (ICR) document prepared by the EPA has been assigned the EPA ICR number 2503.01.

The information collection requirements are based on the recordkeeping and reporting burden associated with developing, implementing, and enforcing a state plan to limit CO_2 emissions from existing sources in the power sector. These recordkeeping and reporting requirements are specifically authorized by CAA section 114 (42 U.S.C. 7414). All information submitted to the EPA pursuant to the recordkeeping and reporting requirements for which a claim of confidentiality is made is safeguarded according to agency policies set forth in 40 CFR part 2, subpart B.

The annual burden for this collection of information for the states (averaged over the first 3 years following promulgation of this proposed action) is estimated to be a range of 316,217 hours at a total annual labor cost of $22,381,044, to 633,001 hours at a total annual labor cost of $44,802,243. The lower bound estimate reflects the assumption that some states already have energy efficiency and renewable energy programs in place. The higher bound estimate reflects the assumption that no states have energy efficiency and renewable energy programs in place. The total annual burden for the federal government (averaged over the first 3 years following promulgation of this proposed action) is estimated to be 53,300 hours at a total annual labor cost of $2,958,005. Burden means the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a federal agency. This includes the time needed to review instructions; develop, acquire, install, and utilize technology and systems for the purposes of collecting, validating, and verifying information, processing and maintaining information, and disclosing and providing information; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to be able to respond to a collection of information; search data sources; complete and review the collection of information; and transmit or otherwise disclose the information.

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 are listed in 40 CFR part 9 and 48 CFR chapter 15.

To comment on the agency's need for this information, the accuracy of the provided burden estimates, and any suggested methods for minimizing respondent burden, the EPA has established a public docket for this rule, which includes this ICR, under Docket ID Number EPA–HQ–OAR–2013–0602. Submit any comments related to the ICR to the EPA and to OMB. See the **ADDRESSES** section at the beginning of this notice for where to submit comments to the EPA. Send comments to OMB at the Office of Information and Regulatory Affairs, Office of Management and Budget, 725 17th Street, NW., Washington, DC 20503, Attention: Desk Office for the EPA. Since OMB is required to make a decision concerning the ICR between 30 and 60 days after June 18, 2014, a comment to OMB is best assured of having its full effect if OMB receives it by July 18, 2014. The final rule will respond to any OMB or public comments on the information collection requirements contained in this proposal.

C. Regulatory Flexibility Act

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

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

(1) A small business that is defined by the SBA's regulations at 13 CFR 121.201 (for the electric power generation industry, the small business size standard is an ultimate parent entity with less than 750 employees. The NAICS codes for the affected industry are in Table 22 below);

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

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

TABLE 22—POTENTIALLY REGULATED CATEGORIES AND ENTITIES [a]

Category	NAICS Code	Examples of potentially regulated entities [a]
Industry	221112	Fossil fuel electric power generating units.
State/Local Government	221112 [b]	Fossil fuel electric power generating units owned by municipalities.

[a] Include NAICS categories for source categories that own and operate electric power generating units (includes boilers and stationary combined cycle combustion turbines).

[b] State or local government-owned and operated establishments are classified according to the activity in which they are engaged.

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

The proposed rule will not impose any requirements on small entities. Specifically, emission guidelines established under CAA section 111(d) do not impose any requirements on regulated entities and, thus, will not have a significant economic impact upon a substantial number of small entities. After emission guidelines are promulgated, states establish standards on existing sources, and it is those state requirements that could potentially impact small entities. Our analysis here is consistent with the analysis of the analogous situation arising when the EPA establishes NAAQS, which do not impose any requirements on regulated entities. As here, any impact of a NAAQS on small entities would only arise when states take subsequent action to maintain and/or achieve the NAAQS through their state implementation plans. See *American Trucking Assoc.* v. *EPA,* 175 F.3d 1029, 1043–45 (D.C. Cir. 1999) (NAAQS do not have significant impacts upon small entities because NAAQS themselves impose no regulations upon small entities).

Nevertheless, the EPA is aware that there is substantial interest in the proposed rule among small entities (municipal and rural electric cooperatives). As detailed in Section III.A of this preamble, the EPA has conducted an unprecedented amount of stakeholder outreach on setting emission guidelines for existing EGUs. While formulating the provisions of the proposed rule, the EPA considered the input provided over the course of the stakeholder outreach. Section III.B of this preamble describes the key messages from stakeholders. In addition, as described in the RFA section of the preamble to the proposed standards of performance for GHG emissions from new EGUs (79 FR 1499–1500, January 8, 2014), the EPA conducted outreach to representatives of small entities while formulating the provisions of the proposed standards. Although only new EGUs would be affected by those proposed standards, the outreach regarded planned actions for new and existing sources. We invite comments on all aspects of the proposal and its impacts, including potential impacts on small entities.

D. Unfunded Mandates Reform Act

This proposed action does not contain a federal mandate that may result in expenditures of $100 million or more for state, local, and tribal governments, in the aggregate, or the private sector in any one year. Specifically, the emission guidelines proposed under CAA section 111(d) do not impose any direct compliance requirements on regulated entities, apart from the requirement for states to develop state plans. The burden for states to develop state plans in the 3-year period following promulgation of the rule was estimated and is listed in Section IX B., above, but this burden is estimated to be below $100 million in any one year. Thus, this proposed rule is not subject to the requirements of section 202 or section 205 of the Unfunded Mandates Reform Act (UMRA).

This proposed rule is also not subject to the requirements of section 203 of UMRA because it contains no regulatory requirements that might significantly or uniquely affect small governments.

In light of the interest among governmental entities, the EPA initiated consultations with governmental entities while formulating the provisions of the proposed standards for new EGUs. Although only new EGUs would be affected by those proposed standards, the outreach regarded planned actions for new and existing sources. As described in the UMRA discussion in the preamble to the proposed standards of performance for GHG emissions from new EGUs (79 FR 1500–1501, January 8, 2014), the EPA consulted with the following 10 national organizations representing state and local elected officials: (1) National Governors Association; (2) National Conference of State Legislatures, (3) Council of State Governments, (4) National League of Cities, (5) U.S. Conference of Mayors, (6) National Association of Counties, (7) International City/County Management Association, 8) National Association of Towns and Townships, (9) County Executives of America, and 10) Environmental Council of States. On February 26, 2014, the EPA re-engaged with those governmental entities to provide a pre-proposal update on the emission guidelines for existing EGUs and emission standards for modified and reconstructed EGUs.

While formulating the provisions of these proposed emission guidelines, the EPA also considered the input provided over the course of the extensive stakeholder outreach conducted by the EPA (see Sections III.A. and III.B. of this preamble).

E. Executive Order 13132, Federalism

Under Executive Order 13132, the EPA may not issue an action that has federalism implications, that imposes substantial direct compliance costs, and that is not required by statute, unless the federal government provides the funds necessary to pay the direct compliance costs incurred by state and local governments, or the EPA consults with state and local officials early in the process of developing the proposed action.

The EPA has concluded that this action may have federalism implications, because it may impose substantial direct compliance costs on state or local governments, and the federal government will not provide the funds necessary to pay those costs. As discussed in the Supporting Statement found in the docket for this rulemaking, the development of state plans will entail many hours of staff time to develop and coordinate programs for compliance with the proposed rule, as well as time to work with state legislatures as appropriate, and develop a plan submittal.

The EPA consulted with state and local officials early in the process of developing the proposed action to permit them to have meaningful and timely input into its development. As described in the Federalism discussion in the preamble to the proposed standards of performance for GHG emissions from new EGUs (79 FR 1501, January 8, 2014), the EPA consulted with state and local officials in the process of developing the proposed standards for newly constructed EGUs. This outreach regarded planned actions for new, reconstructed, modified and existing sources. The EPA invited the following 10 national organizations representing state and local elected officials to a meeting on April 12, 2011, in Washington DC: (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. On February 26, 2014, the EPA re-engaged with those governmental entities to provide a pre-proposal update on the emission guidelines for existing EGUs and emission standards for modified and reconstructed EGUs. In addition, extensive stakeholder outreach conducted by the EPA allowed state leaders, including governors, environmental commissioners, energy officers, public utility commissioners, and air directors, opportunities to engage with EPA officials and provide input regarding reducing carbon pollution from power plants.

A detailed Federalism Summary Impact Statement (FSIS) describing the most pressing issues raised in pre-proposal and post-proposal comments will be forthcoming with the final rule, as required by section 6(b) of Executive Order 13132. In the spirit of Executive Order 13132, and consistent with the EPA's policy to promote communications between the EPA and state and local governments, the EPA specifically solicits comment on this proposed action from State and local officials.

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

This action does not have tribal implications, as specified in Executive Order 13175 (65 FR 67249, November 9, 2000). It would not impose substantial direct compliance costs on tribal governments that have affected EGUs located in their area of Indian country. Tribes are not required to, but may, develop or adopt CAA programs. Tribes are not required to develop plans to implement the guidelines under CAA section 111(d) for affected EGUs. To the extent that a tribal government seeks and attains treatment in a manner similar to a state (TAS) status for that purpose and is delegated authority for air quality planning purposes, these proposed emission guidelines would require that planning requirements be met and emission management implementation plans be executed by the tribes. The EPA is aware of three coal-fired EGUs and one natural gas-fired EGU located in Indian country but is not aware of any affected EGUs that are owned or operated by tribal entities. The EPA notes that this proposal does not directly impose specific requirements on EGU sources, including those located in Indian country, such as the three coal-fired EGUs and one natural gas-fired EGU, but provides guidance to any tribe with delegated authority to address CO_2 emissions from EGU sources found subject to section 111(d) of the CAA. Thus, Executive Order 13175 does not apply to this action.

The EPA conducted outreach to tribal environmental staff and offered consultation with tribal officials in developing this action. Because the EPA is aware of tribal interest in this proposed rule, prior to the April 13, 2012 proposal (77 FR 22392–22441), the EPA offered consultation with tribal officials early in the process of developing the proposed regulation to permit them to have meaningful and timely input into its development. The EPA's consultation regarded planned actions for new and existing sources. In addition, on April 15, 2014, prior to proposal, the EPA met with Navajo Energy Development Group officials. For this proposed action for existing EGUs, a tribe that has one or more affected EGUs located in its area of Indian country [346] would have the opportunity, but not the obligation, to establish a CO_2 performance standard and a CAA section 111(d) plan for its area of Indian country.

Consultation letters were sent to 584 tribal leaders. The letters provided information regarding the EPA's development of both the NSPS and emission guidelines for fossil fuel-fired EGUs and offered consultation. No tribes have requested consultation. Tribes were invited to participate in the national informational webinar held August 27, 2013. In addition, a consultation/outreach meeting was held on September 9, 2013, with tribal representatives from some of the 584 tribes. The EPA also met with tribal environmental staff via National Tribal Air Association teleconferences on July 25, 2013, and December 19, 2013. In those teleconferences, the EPA provided background information on the GHG emission guidelines to be developed and a summary of issues being explored by the agency. Tribes have expressed varied points of view. Some tribes raised concerns about the impacts of the regulations on EGUs and the subsequent impact on jobs and revenue for their tribes. Other tribes expressed concern about the impact the regulations would have on the cost of water to their communities as a result of increased costs to the EGU that provide energy to transport the water to the tribes. Other tribes raised concerns about the impacts of climate change on their communities, resources, life ways and hunting and treaty rights. The tribes were also interested in the scope of the guidelines being considered by the agency (e.g., over what time period, relationship to state and multi-state plans) and how tribes will participate in these planning activities. In addition, the EPA held a series of listening sessions prior to development of this proposed action. In 2013, tribes participated in a session with the state agencies, as well as a separate session with tribes.

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

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

The EPA interprets EO 13045 (62 FR 19885, April 23, 1997) as applying to those regulatory actions that concern health or safety risks, such that the analysis required under section 5–501 of the Order has the potential to influence the regulation. This action is not subject to EO 13045 because it does not involve decisions on environmental health or safety risks that may disproportionately affect children. The EPA believes that the CO_2 emission reductions resulting from implementation of the proposed guidelines, as well as substantial ozone and $PM_{2.5}$ emission reductions as a co-benefit, would further improve children's health.

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

Executive Order 13211 (66 FR 28355; May 22, 2001) requires the EPA to prepare and submit a Statement of Energy Effects to the Administrator of the Office of Information and Regulatory Affairs, OMB, for actions identified as ''significant energy actions.'' This action, which is a significant regulatory action under EO 12866, is likely to have a significant effect on the supply, distribution, or use of energy. We have prepared a Statement of Energy Effects for this action as follows. We estimate a 4 to 7 percent increase in retail electricity prices, on average, across the contiguous U.S. in 2020, and a 16 to 22 percent reduction in coal-fired electricity generation as a result of this rule. The EPA projects that electric power sector delivered natural gas prices will increase by about 8 to 12 percent in 2020. For more information on the estimated energy effects, please refer to the economic impact analysis for this proposal. The analysis is available in the RIA, which is in the public docket.

I. National Technology Transfer and Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act (NTTAA) of 1995 (Pub. L. 104–113; 15 U.S.C. 272 note) directs the EPA to use Voluntary Census Standards (VCS) in its regulatory and procurement activities unless to do so would be inconsistent with applicable law or

[346] The EPA is aware of at least four affected EGUs located in Indian country: Two on Navajo lands, the Navajo Generating Station and the Four Corners Generating Station; one on Ute lands, the Bonanza Generating Station; and one on Fort Mojave lands, the South Point Energy Center. The affected EGUs at the first three plants are coal-fired EGUs. The fourth affected EGU is an NGCC facility.

otherwise impractical. Voluntary consensus standards are technical standards (e.g., materials specifications, test methods, sampling procedures, business practices) developed or adopted by one or more voluntary consensus bodies. The NTTAA directs the EPA to provide Congress, through annual reports to OMB, with explanations when an agency does not use available and applicable VCS. This proposed rulemaking does not involve technical standards.

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

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

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

Section II.A of this preamble summarizes the public health and welfare impacts from GHG emissions that were detailed in the 2009 Endangerment Finding under CAA section 202(a)(1).[347] As part of the Endangerment Finding, the Administrator considered climate change risks to minority or low-income populations, finding that certain parts of the population may be especially vulnerable based on their circumstances. These include the poor, the elderly, the very young, those already in poor health, the disabled, those living alone, and/or indigenous populations dependent on one or a few resources. The Administrator placed weight on the fact that certain groups, including children, the elderly, and the poor, are most vulnerable to climate-related health effects.

Strong scientific evidence that the potential impacts of climate change raise environmental justice issues is found in the major assessment reports by the U.S. Global Change Research Program (USGCRP), the Intergovernmental Panel on Climate Change (IPCC), and the National Research Council (NRC) of the National Academies, summarized in the record for the Endangerment Finding. Their conclusions include that poor communities can be especially vulnerable to climate change impacts because they tend to have more limited adaptive capacities and are more dependent on climate-sensitive resources such as local water and food supplies. In addition, Native American tribal communities possess unique vulnerabilities to climate change, particularly those on established reservations that are restricted to reservation boundaries and therefore have limited relocation options. Tribal communities whose health, economic well-being, and cultural traditions depend upon the natural environment will likely be affected by the degradation of ecosystem goods and services associated with climate change. Southwest native cultures are especially vulnerable to water quality and availability impacts. Native Alaskan communities are likely to experience disruptive impacts, including shifts in the range or abundance of wild species crucial to their livelihoods and well-being. The most recent assessments continue to strengthen scientific understanding of climate change risks to minority and low-income populations.

This proposed rule would limit GHG emissions by establishing CO_2 emission guidelines for existing fossil fuel-fired EGUs. In addition to reducing CO_2 emissions, implementing the proposed rule would reduce other emissions from EGUs that become dispatched less frequently due to their relatively low energy efficiency. These emission reductions will include SO_2 and NOx, which form ambient $PM_{2.5}$ and ozone in the atmosphere, and hazardous air pollutants (HAP), such as mercury and hydrochloric acid. In the final rule revising the annual $PM_{2.5}$ NAAQS,[348] the EPA identified persons with lower socioeconomic status as an at-risk population for experiencing adverse health effects related to PM exposures. Persons with lower socioeconomic status have been generally found to have a higher prevalence of pre-existing diseases, limited access to medical treatment, and increased nutritional deficiencies, which can increase this population's risk to PM-related and ozone-related effects.[349] Therefore, in areas where this rulemaking reduces exposure to $PM_{2.5}$, ozone, and methylmercury, persons with low socioeconomic status would also benefit. The RIA for this rulemaking, included in the docket for this rulemaking, provides additional information regarding the health and ecosystem effects associated with these emission reductions.

While there will be many locations with improved air quality for $PM_{2.5}$, ozone, and HAP, there may also be EGUs whose emissions of one or more of these pollutants or their precursors increase as a result of the proposed emission guidelines for existing fossil fuel-fired EGUs. This may occur at EGUs that become dispatched more intensively than in the past because they become more energy efficient. The EPA has considered the potential for such increases and the environmental justice implications of such increases.

As we noted in the NSR discussion in this preamble, as part of a state's CAA section 111(d) plan, the state may require an affected EGU to undertake a physical or operational changes to improve the unit's efficiency that result in an increase in the unit's dispatch and an increase in the unit's annual emissions of GHGs and/or other regulated pollutants. A state can take steps to avoid increased utilization of particular EGUs and thus avoid any significant increases in emissions including emissions of other regulated pollutants whose environmental effects would be more localized around the affected EGU. To the extent that states take this path, there would be no new environmental justice concerns in the areas near such EGUs. For any EGUs that make modifications that do trigger NSR permitting, the applicable local, state, or federal permitting program will ensure that there are no new NAAQS violations and that no existing NAAQS violations are made worse. For those EGUs in a permitting situation for which the EPA is the permit reviewing authority, the EPA will consider environmental justice issues as required by Executive Order 12898.

In addition to some EGUs possibly being required by a state to make modifications for increased energy efficiency, another effect of the proposed CO_2 emission guidelines for existing fossil fuel-fired EGUs would be

[347] "Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act," 74 FR 66,496 (Dec. 15, 2009) ("Endangerment Finding").

[348] "National Ambient Air Quality Standards for Particulate Matter, Final Rule," 78 FR 3086 (Jan. 15, 2013).

[349] U.S. Environmental Protection Agency (U.S. EPA). 2009. *Integrated Science Assessment for Particulate Matter (Final Report).* EPA–600–R–08–139F. National Center for Environmental Assessment—RTP Division. December. Available on the Internet at *<http://cfpub.epa.gov/ncea/cfm/recordisplay.cfm?deid=216546>*.

increased utilization of other, unmodified EGUs with relatively low GHG emissions per unit of electrical output, in particular high efficiency gas-fired EGUs. Because such EGUs would not have been modified physically nor changed their method of operation, they would not be subject to review in the NSR permitting program. Such plants would have more hours in the year in which they operate and emit pollutants, including pollutants whose environmental effects if any would be localized rather than global as is the case with GHG emissions. Changes in utilization already occur now as demands for and sources of electrical energy evolve, but the proposed CO_2 emission guidelines for existing fossil fuel-fired EGUs can be expected to cause more such changes. Because gas-fired EGUs emit essentially no mercury, increased utilization would not increase methylmercury concentrations in their vicinities. Increased utilization generally would not cause higher peak concentrations of $PM_{2.5}$, NOx, or ozone around such EGUs than is already occurring because peak hourly or daily emissions generally would not change, but increased utilization may make periods of relatively high concentrations more frequent. It should be noted that the gas-fired sources that are likely to become dispatched more frequently than at present have very low emissions of primary particulate matter, SO_2 and HAP per unit of electrical output, such that local (or regional) air quality for these pollutants is likely to be affected very little. For natural gas-fired EGUS, the EPA found that regulation of HAP emissions ''is not appropriate or necessary because the impacts due to HAP emissions from such units are negligible based on the results of the study documented in the utility RTC.'' [350] In studies done by DOE/NETL comparing cost and performance of coal- and NG-fired generation, they assumed SO_2, PM (and Hg) emissions to be ''negligible.'' Their studies predict NOx emissions from a NGCC unit to be approximately 10 times lower than a subcritical or supercritical coal-fired boiler. Many are also very well controlled for emission of NOx through the application of after combustion controls such as selective catalytic reduction, although not all gas-fired sources are so equipped. Depending on the specificity of the state CAA section 111(d) plan, the state may be able to predict which EGUs and communities may be in this type of situation and to address any concerns about localized NO_2 concentrations in the design of the CAA section 111(d) program, or separately from the CAA section 111(d) program but before its implementation. In any case, existing tracking systems will allow states and the EPA to be aware of the EGUs whose utilization has increased most significantly, and thus to be able to prioritize our efforts to assess whether air quality has changed in the communities in the vicinity of such EGUs. There are multiple mechanisms in the CAA to address situations in which air quality has degraded significantly. In conclusion, this proposed rule would result in regional and national pollutant reductions; however, there likely would also be some locations with more times during the year of relatively higher concentrations of pollutants with potential for effects on localized communities than would be experienced in the absence of the proposed rule. The EPA cannot exactly predict how emissions from specific EGUs would change as an outcome of the proposed rule due to the state-led implementation. Therefore, the EPA has concluded that it is not practicable to determine whether there would be disproportionately high and adverse human health or environmental effects on minority, low income, or indigenous populations from this proposed rule.

[350] 65 FR 79831.

In order to provide opportunities for meaningful involvement early on in the rule making process, the EPA has hosted webinars and conference calls on August 27, 2013, and September 9, 2013, on the proposed rule specifically for environmental justice communities and has taken all comments and suggestions into consideration in the design of the emission guidelines.

The public is invited to submit comments or identify peer-reviewed studies and data that assess effects of exposure to the pollutants addressed by this proposal.

XII. Statutory Authority

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

List of Subjects in 40 CFR Part 60

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

Dated: June 2, 2014.

Gina McCarthy,

Administrator.

For the reasons stated in the preamble, title 40, chapter I, part 60 of the Code of the Federal Regulations is proposed to be amended as follows:

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

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

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

■ 2. Section 60.27 is amended by revising paragraph (b) to read as follows:

§ 60.27 Actions by the Administrator.

* * * * *

(b) After receipt of a plan or plan revision, the Administrator will propose the plan or revision for approval or disapproval. The Administrator will, within four months after the date required for submission of a plan or plan revision, approve or disapprove such plan or revision or each portion thereof, except as provided in § 60.5715.

* * * * *

■ 3. Add subpart UUUU to read as follows:

Subpart UUUU: Emission Guidelines for Greenhouse Gas Emissions and Compliance Times for Electric Utility Generating Units

Sec.

Introduction

State Plan

Introduction

§ 60.5700 What is the purpose of this subpart?

This subpart establishes emission guidelines and approval criteria for state plans that establish emission standards limiting the control of greenhouse gas emissions from an affected steam generating unit, integrated gasification combined cycle (IGCC), or stationary combustion turbine. An affected steam generating unit, IGCC, or stationary combustion turbine shall, for the purposes of this subpart, be referred to as an affected EGU. These emission guidelines are developed in accordance with sections 111(d) of the Clean Air Act and subpart B of this part. To the extent any requirement of this subpart is inconsistent with the requirements of subparts A or B of this part, the requirements of this subpart will apply.

§ 60.5705 What pollutants are regulated by this subpart?

(a) The pollutants regulated by this subpart are greenhouse gases.

(b) The greenhouse gas regulated by this subpart is carbon dioxide (CO_2).

§ 60.5710 Am I affected by this subpart?

If you are the Administrator of an air quality program in a state with one or more affected EGUs that commenced construction on or before January 8, 2014, you must submit a state plan to the U.S. Environmental Protection Agency (EPA) that implements the emission guidelines contained in this subpart. You must submit a negative declaration letter in place of the state plan if there are no affected EGUs for which construction commenced on or before January 8, 2014 in your state.

§ 60.5715 What is the review and approval process for my state plan?

The EPA will review your state plan according to § 60.27 except that under § 60.27(b) the Administrator will have twelve months after the date required for submission of a plan or plan revision to approve or disapprove such plan or revision or each portion thereof. If you submit a request for extension under § 60.5760(a) in lieu of a complete state plan the EPA will follow the procedure in § 60.5760(b).

§ 60.5720 What if I do not submit a plan or my plan is not approvable?

If you do not submit an approvable state plan the EPA will develop a Federal plan for your state according to § 60.27 to implement the emission guidelines contained in this subpart. Owners and operators of affected entities not covered by an approved state plan must comply with a Federal plan implemented by the EPA for the state. The Federal plan is an interim action and will be automatically withdrawn when your state plan is approved.

§ 60.5725 In lieu of a state plan submittal, are there other acceptable option(s) for a state to meet its section 111(d) obligations?

A state may meet its CAA section 111(d) obligations only by submitting a complete state plan or a negative declaration letter (if applicable).

§ 60.5730 Is there an approval process for a negative declaration letter?

No. The EPA has no formal review process for negative declaration letters. Once your negative declaration letter has been received, the EPA will place a copy in the public docket and publish a notice in the **Federal Register**. If, at a later date, an affected EGU for which construction commenced on or before January 8, 2014 is found in your state, a Federal plan implementing the emission guidelines contained in this subpart would automatically apply to that affected EGU until your state plan is approved.

§ 60.5735 What authorities will not be delegated to state, local, or tribal agencies?

The authorities that will not be delegated to State, local, or tribal agencies are specified in paragraph (a) of this section.

(a) Approval of alternatives, not already approved by this subpart, to the emissions performance goals in Table 1 to this subpart established under § 60.5755.

(b) [Reserved]

State Plan

§ 60.5740 What must I include in my state plan?

(a) You must include the elements described in paragraphs (a)(1) through (11) of this section in your state plan.

(1) Identification of affected entities, including an inventory of CO_2 emissions from affected EGUs during the most recent calendar year prior to the submission of the plan for which data is available.

(2) A description of plan approach and the geographic scope of a plan (state or multi-state), including, if relevant, identification of multi-state plan participants and geographic boundaries related to plan elements.

(3) Identification of the state emission performance level for affected entities that will be achieved through implementation of the plan.

(i) The plan must specify the average emissions performance that the plan will achieve for the following periods:

(A) The 10 year interim plan performance period of 2020 through 2029.

(B) The single projection year of 2030.

(ii) The identified emission performance level for each plan performance period in paragraph (a)(3)(i) of this section must be equivalent to or better than the levels of the rate-based CO_2 emission performance goals in Table 1 of this Subpart for affected entities in your state. The emission performance levels may be in either a rate-based form or a mass based form which is calculated according to § 60.5770. The CO_2 emission performance level specified must include either of the following as applicable:

(A) For a rate-based CO_2 emission performance level, the identified level must represent the CO_2 emissions rate, in pounds of CO_2 per MWh of net energy output that will be achieved by affected entities.

(B) For a mass-based CO_2 emission performance level, the identified level of performance must represent the total tons of CO_2 that will be emitted by affected entities during each plan performance period.

(iii) For the interim plan performance period you must identify the emission performance levels anticipated under the plan during each year 2020 through 2029.

(4) A demonstration that the plan is projected to achieve each of the state's emission performance levels for affected entities according to paragraph (a)(3) of this section.

(5) Identification of emission standards for each affected entity, compliance periods for each emission standard, and demonstration that the emission standards are, when taken together, sufficiently protective to meet the state emissions performance level.

(6) A demonstration that each emission standard is quantifiable, non-duplicative, permanent, verifiable, and enforceable with respect to an affected entity.

(7) If your state plan does not require achievement of the full level of required emission performance, and the identified interim increments of performance in paragraph (a)(3)(iii) of this section, through emission limits on EGUs, the plan must specify the following:

(i) Program implementation milestones (e.g., start of an end-use energy efficiency program, retirement of an affected EGU, or increase in portfolio requirements under a renewable portfolio standard) and milestone dates that are appropriate to the requirements, programs, and measures included in the plan.

(ii) Corrective measures that will be implemented in the event that the comparison required by § 60.5815(b) of projected versus actual emissions performance of affected entities shows that actual emissions performance is greater than 10 percent in excess to projected plan performance for the period described in § 60.5775(c)(1), and a process and schedule for implementing such corrective measures.

(8) Identification of applicable monitoring, reporting, and recordkeeping requirements for each affected entity. If applicable, these requirements must be consistent with the requirements specified in § 60.5810.

(9) Description of the process, contents, and schedule for annual state reporting to the EPA about plan implementation and progress including information required under § 60.5815.

(10) Certification that the hearing on the state plan was held, a list of witnesses and their organizational affiliations, if any, appearing at the hearing, and a brief written summary of each presentation or written submission.

(11) Supporting material including:

(i) Materials demonstrating the state's legal authority to carry out each component of its plan, including emissions standards;

(ii) Materials supporting the projected emissions performance level that will be achieved by affected entities under the plan, according to paragraph (a)(4) of this section;

(iii) Materials supporting the projected mass-based emission performance goal, calculated pursuant to § 60.5770, if applicable; and

(iv) Materials necessary to support evaluation of the plan by the EPA.

(b) You must follow the requirements of subpart B of this part (Adoption and Submittal of state plans for Designated Facilities) and demonstrate that they were met in your state plan.

§ 60.5745 Can I work with other states to develop a multi-state plan?

A multi-state plan may be submitted, provided it is signed by authorized officials for each of the states participating in the multi-state plan. In this instance, the joint submittal will have the same legal effect as an individual submittal for each participating state. A multi-state plan will include all the required elements for a single-state plan specified in § 60.5740(a). A multi-state plan, if submitted by a state, must:

(a) Demonstrate CO_2 emission performance jointly for all affected entities in all states participating in the multi-state plan, as follows:

(1) For states demonstrating performance based on the CO_2 emission rate, the level of performance identified in the multi-state plan pursuant to § 60.5740(a)(3) will be a weighted (by net energy output) average lb CO_2/MWh emission rate to be achieved by all affected EGUs in the multi-state area during the plan performance period; or

(2) For states demonstrating performance based on mass CO_2 emissions, the level of performance identified in the multi-state plan pursuant to 60.5740(a)(3) will be total CO_2 emissions by all affected EGUs in the multi-state area during the plan performance period.

(b) Assign among states, according to a formula in the multi-state plan, avoided CO_2 emissions resulting from emission standards contained in the plan, from affected entities in states participating in the multi-state plan.

§ 60.5750 Can I include existing requirements, programs, and measures in my state plan?

(a) Yes, you may include existing requirements, programs and measures in your plan according to paragraphs (b) through (d) of this section.

(b) Existing state programs, requirements, and measures, may qualify for use in demonstrating that a state plan achieves the required level of emission performance specified in a plan, according to § 60.5740(a)(3).

(c) Existing state programs, requirements, and measures, may qualify for use in projecting that a state plan will achieve the required level of emission performance specified in a plan, according to § 60.5740(a)(4).

(d) Emission impacts of existing programs, requirements, and measures that occur during a plan performance period may be recognized in meeting or projecting CO_2 emission performance by affected EGUs according to § 60.5740(a)(3) and (4), as long as they meet the following requirements:

(1) Actions taken pursuant to an existing state program, requirement, or measure, such as compliance with a regulatory obligation or initiation of an action related to a program or measure, must occur after June 18, 2014; and

(2) The existing state program, requirement, or measure, and any related actions taken pursuant to such program, requirement, or measure, meet the applicable requirements pursuant to § 60.5740(a) and § 60.5780.

§ 60.5755 What are the timing requirements for submitting my state plan?

(a) You must submit your state plan with the information in § 60.5740 by June 30, 2016 unless you are submitting a request for extension according to paragraphs (b) or (c) of this section.

(b) For a state seeking a one year extension for a complete plan submittal you must include the information in § 60.5760(a) in a submittal by June 30, 2016 to receive an extension to submit your complete state plan by June 30, 2017.

(c) For states in a multi-state plan seeking a two year extension for a complete plan submittal you must include the information in § 60.5760(a) in a submittal by June 30, 2016 to receive an extension to submit your complete multi-state plan by June 30, 2018.

§ 60.5760 What must I include in an initial submittal in lieu of a complete state plan?

(a) You must include the following required elements in an initial submittal in lieu of a complete state plan:

(1) A description of the plan approach and progress made to date in developing each of the plan elements in § 60.5740;

(2) An initial projection of the level of emission performance that will be achieved under the complete plan;

(3) A commitment by the state to maintain existing state programs and

measures that limit or avoid CO_2 emissions from affected entities (e.g., renewable energy standards, unit-specific limits on operation or fuel utilization), which must at a minimum apply during the interim period prior to state submission and EPA approval of a complete plan, and must continue to apply in lieu of a complete plan if one is ultimately not submitted and approved;

(4) Justification of why additional time is needed to submit a complete plan;

(5) A comprehensive roadmap for completing the plan, including process, analytical methods and schedule (including milestones) specifying when all necessary plan components will be complete (e.g., projection of emission performance; implementing legislation, regulations and agreements; necessary approvals);

(6) Identification of existing and future programs, requirements, and measures the state intends to include in the plan;

(7) If a multi-state plan is being developed, an executed agreement(s) with other states (e.g., MOU) participating in the development of the multistate plan; and

(8) A commitment to submit a complete plan by June 30, 2017, for a single-state plan, or June 30, 2018, for a multi-state plan, and actions the state will take to show progress in addressing incomplete plan components prior to submittal of the complete plan.

(9) A description of all steps the state has already taken in furtherance of actions needed to finalize a complete plan.

(10) Evidence of an opportunity for public comment and a response to any significant comments received on issues relating to the approvability of the initial plan.

(b) You must submit either a complete state plan or an initial submittal by June 30, 2016. Where an initial submittal is submitted in lieu of a complete state plan the due date of a complete state plan will be June 30, 2017, for a single-state plan, or June 30, 2018, for a multi-state plan unless a state is notified within 60 days of the EPA receiving the initial submittal in paragraph (a) of this section that the EPA finds the initial submittal does not meet the requirements listed in paragraph (a) of this section.

§ 60.5765 What are the state rate-based CO_2 emissions performance goals?

(a) The annual average state rate-based CO_2 emission performance goals for the interim performance periods of 2020 through 2029, and the final 2030 and thereafter period are respectively listed in Table 1 of this Subpart. The state rate-based CO_2 emission performance goal may be converted to a mass-based emission performance goal according to § 60.5770.

(b)[Reserved]

§ 60.5770 What is the procedure for converting my state rate-based CO_2 emission performance goal to a mass-based CO_2 emissions performance goal?

(a) If the plan adopts a mass-based goal according to § 60.5740(a)(3), the plan must identify the mass-based goal, in tons of CO_2 emitted by affected EGUs over the plan performance period, and include a description of the analytic process, tools, methods, and assumptions used to convert from the rate-based goal for the state identified in Table 1 of this Subpart to an equivalent mass-based goal. The conversion process must include following requirements:

(1) The process, tools, methods, and assumptions used in the conversion of the rate-based goal must be included in your state plan according to § 60.5740(a)(11).

(2) The material supporting the conversion of the rate-based goal, including results, data, and descriptions, must be include in a state plan according to § 60.5740(a)(11).

(3) The conversion must represent the tons of CO_2 emissions that are projected to be emitted by affected EGUs, in the absence of emission standards contained in the plan, if the affected EGUs were to perform at an average lb CO_2/MWh rate equal to the rate-based goal for the state identified in Table 1 of this Subpart.

(b) [Reserved]

§ 60.5775 What schedules, performance periods, and compliance periods must I include in my state plan?

(a) Your state plan must include a schedule of compliance for each affected entity regulated under the plan.

(b) Your state plan must include compliance periods, as defined in section § 60.5820, for each affected entity regulated under the plan.

(c) For the interim performance period of 2020–2029 your state must meet the requirements in paragraphs (c)(1) and (2) of this section.

(1) Your state plan must include increments of emissions performance (either rate based or mass based with respect to the interim level of performance set in the state plan) within the interim performance period for every 2-rolling calendar years starting January 1, 2020 and ending in 2028 (i.e. 2020–2021, 2021–2022, 2022–2023, etc.), unless other periods that ensure regular progress in the interim period are approved by the Administrator.

(2) At the end of 2029 your state must meet the interim emissions performance level specified in § 60.5740(a)(3) as averaged over the plan performance period 2020–2029.

(d) During the final performance period, 2030 and thereafter, your state must meet the final emission performance level specified in § 60.5740(a)(3) on a 3-calendar year rolling average starting January 1, 2030 (i.e., 2030–2032, 2031–2033, 2032–2034, etc.).

(e) You must include the provisions of your state plan which demonstrate progress and compliance with the requirements in this § 60.5775 and § 60.5740 in your state's annual report required in § 60.5815.

§ 60.5780 What emission standards and enforcing measures must I include in my plan?

(a) Your state plan shall include emission standard(s) that are quantifiable, verifiable, non-duplicative, permanent, and enforceable with respect to each affected entity. The plan shall include the methods by which each emission standard meets each of the following requirements in paragraphs (b) through (f) of this section.

(b) An emission standard is quantifiable with respect to an affected entity if it can be reliably measured, in a manner that can be replicated.

(c) An emission standard is verifiable with respect to an affected entity if adequate monitoring, recordkeeping and reporting requirements are in place to enable the state and the Administrator to independently evaluate, measure, and verify compliance with the emission standard.

(d) An emission standard is non-duplicative with respect to an affected entity if it is not already incorporated as an emission standard in another state plan unless incorporated in multi-state plan.

(e) An emission standard is permanent with respect to an affected entity if the emission standard must be met for each compliance period, or unless it is replaced by another emission standard in an approved plan revision, or the state demonstrates in an approved plan revision that the emission reductions from the emission standard are no longer necessary for the state to meet its state level of performance.

(f) An emission standard is enforceable against an affected entity if:

(1) A technically accurate limitation or requirement and the time period for

the limitation or requirement is specified;

(2) Compliance requirements are clearly defined;

(3) The affected entities responsible for compliance and liable for violations can be identified;

(4) Each compliance activity or measure is enforceable as a practical matter; and

(5) The Administrator and the state maintain the ability to enforce violations and secure appropriate corrective actions pursuant to sections 113(a) through (h) of the Act.

§ 60.5785 What is the procedure for revising my state plan?

State plans can only be revised with approval by the Administrator. If one (or more) of the elements of the state plan set in § 60.5740 require revision with respect to reaching the emission performance goal set in § 60.5765 a request may be submitted to the Administrator indicating the proposed corrections to the state plan to ensure the emission performance goal is met.

Applicability of State Plans to Affected EGUs

§ 60.5790 Does this subpart directly affect EGU owners and operators in my state?

(a) This subpart does not directly affect EGU owners and operators in your state. However, EGU owners and operators must comply with the state plan that a state develops to implement the emission guidelines contained in this subpart.

(b) If a state does not submit an approvable plan or initial submittal to implement and enforce the emission guidelines contained in this subpart by June 30, 2016, the EPA will implement and enforce a Federal plan, as provided in § 60.5740, to ensure that each affected EGU within the state that commenced construction on or before January 8, 2014 reaches compliance with all the provisions of this subpart.

§ 60.5795 What affected EGUs must I address in my state plan?

(a) The EGUs that must be addressed by your state plan are any affected steam generating unit, IGCC, or stationary combustion turbine that commences construction on or before January 8, 2014.

(b) An affected EGU is a steam generating unit, integrated gasification combined cycle (IGCC), or stationary combustion turbine that meets the relevant applicability conditions specified in paragraph (b)(1) or (2) of this section.

(1) A steam generating unit or IGCC that has a base load rating greater than 73 MW (250 MMBtu/h) heat input of fossil fuel (either alone or in combination with any other fuel) and was constructed for the purpose of supplying one-third or more of its potential electric output and more than 219,000 MWh net-electric output to a utility distribution system on an annual basis.

(2) A stationary combustion turbine that has a base load rating greater than 73 MW (250 MMBtu/h), was constructed for the purpose of supplying, and supplies, one-third or more of its potential electric output and more than 219,000 MWh net-electrical output to a utility distribution system on a 3-year rolling average basis, combusts fossil fuel for more than 10.0 percent of the heat input during a 3-year rolling average basis and combusts over 90% natural gas on a heat input basis on a 3-year rolling average basis.

§ 60.5800 What affected EGUs are exempt from my state plan?

Affected EGUs that are exempt from your state plan include: those that are subject to subpart TTTT as a result of commencing construction or reconstruction after the subpart TTTT applicability date; and those subject to subpart TTTT as a result of commencing modification or reconstruction prior becoming subject to an applicable state plan.

§ 60.5805 What applicable monitoring, recordkeeping, and reporting requirements do I need to include in my state plan for affected EGUs?

(a) A state plan must include monitoring that is no less stringent that what is described in (a)(1) through (6) of this section.

(1) If an affected EGU is required to meet a rate based emission standard they must prepare a monitoring plan in accordance with the applicable provisions in § 75.53(g) and (h) of this chapter.

(2) An affected EGU must measure the hourly CO_2 mass emissions from each affected unit using the procedures in paragraphs (a)(2)(i) through (v) of this section, except as provided in paragraph (a)(3) of this section.

(i) An affected EGU must install, certify, operate, maintain, and calibrate a CO_2 continuous emissions monitoring system (CEMS) to directly measure and record CO_2 concentrations in the affected EGU exhaust gases emitted to the atmosphere and an exhaust gas flow rate monitoring system according to § 75.10(a)(3)(i) of this chapter. If an affected EGU measures CO_2 concentration on a dry basis, they must also install, certify, operate, maintain, and calibrate a continuous moisture monitoring system, according to § 75.11(b) of this chapter.

(ii) For each monitoring system an affected EGU uses to determine the CO_2 mass emissions, they must meet the applicable certification and quality assurance procedures in § 75.20 of this chapter and Appendices B and D to part 75 of this chapter.

(iii) An affected EGU must use a laser device to measure the dimensions of each exhaust gas stack or duct at the flow monitor and the reference method sampling locations prior to the initial setup (characterization) of the flow monitor. For circular stacks, an affected EGU must measure the diameter at three or more distinct locations and average the results. For rectangular stacks or ducts, an affected EGU must measure each dimension (i.e., depth and width) at three or more distinct locations and average the results. If the flow rate monitor or reference method sampling site is relocated, an affected EGU must repeat these measurements at the new location.

(iv) An affected EGU must use only unadjusted exhaust gas volumetric flow rates to determine the hourly CO_2 mass emissions from the affected facility; an affected EGU must not apply the bias adjustment factors described in section 7.6.5 of Appendix A to part 75 of this chapter to the exhaust gas flow rate data.

(v) If an affected EGU chooses to use Method 2 in Appendix A–1 to this part to perform the required relative accuracy test audits (RATAs) of the part 75 flow rate monitoring system, they must use a calibrated Type-S pitot tube or pitot tube assembly. An affected EGU must not use the default Type-S pitot tube coefficient.

(3) If an affected EGU exclusively combusts liquid fuel and/or gaseous fuel as an alternative to complying with paragraph (b) of this section, they may determine the hourly CO_2 mass emissions by using Equation G–4 in Appendix G to part 75 of this chapter according to the requirements in paragraphs (a)(3)(i) and (ii) of this section.

(i) An affected EGU must implement the applicable procedures in appendix D to part 75 of this chapter to determine hourly unit heat input rates (MMBtu/h), based on hourly measurements of fuel flow rate and periodic determinations of the gross calorific value (GCV) of each fuel combusted.

(ii) An affected EGU may determine site-specific carbon-based F-factors (F_c) using Equation F–7b in section 3.3.6 of appendix F to part 75 of this chapter, and may use these F_c values in the emissions calculations instead of using the default F_c values in the Equation G–4 nomenclature.

(4) An affected EGU must install, calibrate, maintain, and operate a sufficient number of watt meters to continuously measure and record on an hourly basis net electric output. Measurements must be performed using 0.2 accuracy class electricity metering instrumentation and calibration procedures as specified under ANSI Standards No. C12.20. Further, an affected EGU that is a combined heat and power facility must install, calibrate, maintain and operate equipment to continuously measure and record on an hourly basis useful thermal output and, if applicable, mechanical output, which are used with net electric output to determine net energy output.

(5) In accordance with § 60.13(g), if two or more affected EGUs that implement the continuous emissions monitoring provisions in paragraph (a)(2) of this section share a common exhaust gas stack and are subject to the same emissions standard, they may monitor the hourly CO_2 mass emissions at the common stack in lieu of monitoring each EGU separately. If an affected EGU chooses this option, the hourly net electric output for the common stack must be the sum of the hourly net electric output of the individual affected facility and you must express the operating time as ''stack operating hours'' (as defined in § 72.2 of this chapter).

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

(b) An affected EGU must maintain records for at least 10 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

(1) An affected EGU must maintain each record on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to § 60.7. An affected EGU may maintain the records off site and electronically for the remaining year(s).

(c) An affected EGU must include in a report required by the state plan covering each compliance period all hourly CO_2 emissions and all hourly net electric output and all hourly net energy output measurements for a CHP facility calculated from data monitored according to paragraph (a) of this section.

Recordkeeping and Reporting Requirements

§ 60.5810 What are my state recordkeeping requirements?

(a) States must keep records of all plan components, plan requirements, supporting documentation, and the status of meeting the plan requirements defined in the state plan on an annual basis during the interim plan performance period from 2020–2029. After 2029 states must keep records of all information that is used to support any continued effort to meet the final emissions performance goal.

(b) States must keep records of all data submitted by each affected entity that is used to determine compliance with each affected entity's emissions standard.

(c) If a state has a requirement for hourly CO_2 emissions and net generation information to be used to calculate compliance with an annual emissions standard for affected EGUs, any information that is submitted to the EPA electronically pursuant to requirements in Part 75 would meet the recordkeeping requirement of this section and a state would not need to keep records of information that would be in duplicate of paragraph (b) of this section.

(d) A state must keep records at minimum for 20 years.

§ 60.5815 What are my state reporting requirements?

(a) You must submit an annual report covering each calendar year no later than July 1 of the following year, starting July 1 2021. The annual report must include the following:

(1) The level of emissions performance achieved by all affected entities and identification of whether affected entities are on schedule to meet the applicable level of emissions performance for affected entities during the plan performance period and compliance periods, as specified in the plan.

(2) The level of emissions performance achieved by all affected EGUs during the reporting period, and prior reporting periods, expressed as average CO_2 emissions rate or total mass CO_2 emissions, consistent with the plan approach, and identification of whether affected EGUs are on schedule to meet the applicable level of emissions performance for affected EGUs during the plan performance period, as specified in the plan.

(3) A list of affected entities and their compliance status with the applicable emissions standards specified in the state plan.

(4) A list of all affected EGUs and their reported CO_2 emissions performance for each compliance period during the reporting period, and prior reporting periods.

(5) All other required information, as specified in your state plan according to § 60.5740(a)(9).

(6) All information required by § 60.5775(e).

(b) For each two-year period in § 60.5775(c)(1), you must compare the average CO_2 emission performance achieved by affected entities in the state versus the CO_2 emission performance projected in the state plan. If actual emission performance is greater than 10 percent in excess to projected plan performance for a two-year comparison period, you must explain the reasons for the deviation and specify the corrective actions that will be taken to ensure that the required interim and final levels of emission performance in the plan will be met. The information required in this paragraph must be included in the annual report required by paragraph (a) of this section.

(c) You must include in your 2029 annual report (which is subsequently due by July 1, 2030) the calculation of average emissions over the 2020–2029 interim performance period used to determine compliance with your interim emission performance level. The calculated value must be in units consistent with your interim emission performance level.

(d) You must include in each report, starting with the 2032 annual report (which is subsequently due by July 1, 2033), a 3-calendar year rolling average used to determine compliance with the final emission performance level. The calculated value must be in units consistent with your final emission performance level.

Definitions

§ 60.5820 What definitions apply to this subpart?

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

Affected electric generating unit or *Affected EGU* means a steam generating unit, an IGCC facility, or a stationary combustion turbine that meets the applicability conditions in section § 60.5795.

Affected Entity shall mean any of the following: An affected EGU, or another entity with obligations under this subpart for the purpose of meeting the emissions performance goal requirements in these emission guidelines.

Base load rating means the maximum amount of heat input (fuel) that a steam generating unit can combust on a steady state basis, as determined by the physical design and characteristics of the steam generating unit at ISO conditions. For a stationary combustion turbine, *base load rating* means 100 percent of the design heat input capacity of the simple cycle portion of the stationary combustion turbine at ISO conditions (heat input from duct burners is not included).

CO_2 emissions performance goal means the rate-based CO_2 emissions performance goal specified for a state in Table 1 of this subpart, or a translated mass-based form of that goal.

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

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

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

Compliance period means the period of time, set forth by a state in its state plan, during which each affected entity must demonstrate compliance with an applicable emissions standard, and shall be no greater than a three year period for a mass-based plan, and shall be no greater than a one year period for a rate-based plan.

Emission performance level in a state plan means the level of emissions performance for affected entities specified in a state plan, according to § 60.5740.

Emission standard means in addition to the definition in § 60.21, any requirement applicable to any affected entity other than an affected source that has the effect of reducing utilization of one or more affected sources, thereby avoiding emissions from such sources, including, for example, renewable energy and demand-side energy efficiency measures requirements.

Excess emissions means a specified averaging period over which the CO_2 emissions rate is higher than an applicable emissions standard or an averaging period during which an affected EGU is not in compliance with any other emission limitation specified in an emission standard.

Existing state program, requirement, or measure means, in the context of a state plan, a regulation, requirement, program, or measure administered by a state, utility, or other entity that is currently established. This may include a regulation or other legal requirement that includes past, current, and future obligations, or current programs and measures that are in place and are anticipated to be continued or expanded in the future, in accordance with established plans. An existing state program, requirement, or measure may have past, current, and future impacts on EGU CO_2 emissions.

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

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

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

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

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

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

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

Natural gas means a fluid mixture of hydrocarbons (e.g., methane, ethane, or propane), composed of at least 70 percent methane by volume or that has a gross calorific value between 35 and 41 megajoules (MJ) per dry standard cubic meter (950 and 1,100 Btu per dry standard cubic foot), that maintains a gaseous state under ISO conditions. In addition, natural gas contains 20.0 grains or less of total sulfur per 100 standard cubic feet. Finally, natural gas does not include the following gaseous fuels: Landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable sulfur content or heating value.

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

Net energy output means:

(1) The net electric or mechanical output from the affected facility, plus 75 percent of the useful thermal output measured relative to SATP conditions that is not used to generate additional electric or mechanical output or to enhance the performance of the unit (e.g., steam delivered to an industrial process for a heating application).

(2) For combined heat and power facilities where at least 20.0 percent of

the total gross energy output consists of electric or direct mechanical output and 20.0 percent of the total gross energy output consists of useful thermal output on a rolling 3 year basis, the net electric or mechanical output from the affected facility divided by 0.95, plus 75 percent of the useful thermal output measured relative to SATP conditions that is not used to generate additional electric or mechanical output or to enhance the performance of the unit (e.g., steam delivered to an industrial process for a heating application).

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

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

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

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

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

Useful thermal output means the thermal energy made available for use in any industrial or commercial process, or used in any heating or cooling application, i.e., total thermal energy made available for processes and applications other than electric generation, mechanical output at the affected facility, or to directly enhance the performance of the affected facility (e.g., economizer output is not useful thermal output, but thermal energy used to reduce fuel moisture is considered useful thermal output). Useful thermal output for affected facilities with no condensate return (or other thermal energy input to the affected facility) or where measuring the energy in the condensate (or other thermal energy input to the affected facility) would not meaningfully impact the emission rate calculation is measured against the energy in the thermal output at SATP conditions. Affected facilities with meaningful energy in the condensate return (or other thermal energy input to the affected facility) must measure the energy in the condensate and subtract that energy relative to SATP conditions from the measured thermal output.

TABLE 1 TO SUBPART UUUU OF PART 60—STATE RATE-BASED CO_2 EMISSION PERFORMANCE GOALS

[Pounds of CO_2 per net MWh]

State	Interim goal	Final goal
Alabama	1,147	1,059
Alaska	1,097	1,003
Arizona	735	702
Arkansas	968	910
California	556	537
Colorado	1,159	1,108
Connecticut	597	540
Delaware	913	841
Florida	794	740
Georgia	891	834
Hawaii	1,378	1,306
Idaho	244	228
Illinois	1,366	1,271
Indiana	1,607	1,531
Iowa	1,341	1,301
Kansas	1,578	1,499
Kentucky	1,844	1,763
Louisiana	948	883
Maine	393	378
Maryland	1,347	1,187
Massachusetts	655	576
Michigan	1,227	1,161
Minnesota	911	873
Mississippi	732	692
Missouri	1,621	1,544
Montana	1,882	1,771
Nebraska	1,596	1,479
Nevada	697	647
New Hampshire	546	486
New Jersey	647	531
New Mexico	1,107	1,048
New York	635	549
North Carolina	1,077	992
North Dakota	1,817	1,783

TABLE 1 TO SUBPART UUUU OF PART 60—STATE RATE-BASED CO_2 EMISSION PERFORMANCE GOALS—Continued

[Pounds of CO_2 per net MWh]

State	Interim goal	Final goal
Ohio	1,452	1,338
Oklahoma	931	895
Oregon	407	372
Pennsylvania	1,179	1,052
Rhode Island	822	782
South Carolina	840	772
South Dakota	800	741
Tennessee	1,254	1,163
Texas	853	791
Utah	1,378	1,322
Virginia	884	810
Washington	264	215
West Virginia	1,748	1,620
Wisconsin	1,281	1,203
Wyoming	1,808	1,714

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