Hi Bob,

Attached are additional interagency comments (in redline form) on the 111(d) preamble.

Regards,
Cortney

<< EO12866_GHG EGU ExistingSources 2060-AR33 Proposal_InteragencyCommentsUnder EO12866_05072014.docx >>
CARBON POLLUTION GUIDELINES FOR EXISTING POWER PLANTS:
EMISSION GUIDELINES FOR GREENHOUSE GAS EMISSIONS FROM EXISTING
STATIONARY SOURCES: ELECTRIC UTILITY GENERATING UNITS

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: In this action, the EPA is proposing emission guidelines for states to use 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 use in developing plans to attain the state-specific goals. This rule, as proposed, would set in motion actions to reduce carbon dioxide emissions from the electric power sector in the United States.

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

**Public Hearing.** Public hearings will be held on [INSERT DATES HERE], at [INSERT LOCATIONS HERE]. The hearings will convene at [INSERT TIME] and end at [INSERT TIME]. Please contact [add name] at [phone#] or at xxx.xxx@epa.gov to register to speak at one of the hearings. The last day to pre-register in advance to speak at the hearing will be [INSERT DATE HERE]. Additionally, requests to speak will be taken the day of the hearing 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 hearing 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 this hearing is being

Comment [A1]: Does EPA have this information now?
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. 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. Written comments on the proposed rule must be postmarked by [INSERT DATE HERE]. Commenters should notify [ADD NAME] if they will need specific equipment, or if there are other special needs related to providing comments at the hearing. The EPA will provide equipment for commenters to show overhead slides or make computerized slide presentations if we receive special requests in advance. Oral testimony will be limited to 5 minutes for each commenter. The EPA encourages
commenters to provide the EPA with a copy of their oral testimony electronically (via email or CD) or in hard copy form. 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 hearing to run either ahead of schedule or behind schedule. Information regarding the hearing (including information as to whether or not one will be held) will be available at: http://www2.epa.gov/carbon-pollution-standards/.

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

At the website http://www.regulations.gov: Follow the instructions for submitting comments.

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

Email: Send your comments by electronic mail (email) to a-and-r-docket@epa.gov, Attn: Docket ID No. EPA-HQ-OAR-2013-0602.


Mail: Send your comments to the EPA Docket Center, U.S. EPA, Mail Code 2822T, 1200 Pennsylvania Ave., NW, Washington, DC
20460, Attn: Docket ID No. EPA-HQ-OAR-2013-0602. Please include a total of two copies. 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 Delivery or Courier: Deliver your comments to the EPA Docket Center, William Jefferson Clinton Building West, Room 3334, 1301 Constitution Ave., NW, Washington, DC, 20004, Attn: Docket ID No. EPA-HQ-OAR-2013-0602. 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 website is an “anonymous access” system, which means the EPA will not know your identity or contact information unless you provide it in the body of your
comment. If you send an email comment directly to the EPA without going through http://www.regulations.gov, your email address will be automatically captured and included as part of the comment that is placed in the public docket and made available on the Internet. If you submit an electronic comment, the EPA recommends that you include your name and other contact information in the body of your comment and with any disk or CD-ROM you submit. If the EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, the EPA may not be able to consider your comment. Electronic files should avoid the use of special characters, any form of encryption and be free of any defects or viruses.

Docket: All documents in the docket are listed in the http://www.regulations.gov index. Although listed in the index, some information is not publicly available (e.g., CBI or other information whose disclosure is restricted by statute). Certain other material, such as copyrighted material, will be publicly available only in hard copy. Publicly available docket materials are available either electronically 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) through the Technology Transfer Network (TTN). Following signature, a copy of the proposed rule will be posted on the TTN’s policy and guidance page for newly proposed or promulgated rules at the following address: http://www.epa.gov/ttn/oarpg/.

FOR FURTHER INFORMATION CONTACT: [ADD CONTACTS]

SUPPLEMENTARY INFORMATION: [INSERT TEXT, AS APPROPRIATE]

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)
<table>
<thead>
<tr>
<th>Abbreviation</th>
<th>Full Form</th>
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<tr>
<td>CEMS</td>
<td>Continuous Emissions Monitoring System</td>
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<td>CHP</td>
<td>Combined Heat and Power</td>
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<td>CO₂</td>
<td>Carbon Dioxide</td>
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<tr>
<td>DOE</td>
<td>Department of Energy</td>
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<td>ECMPS</td>
<td>Emissions Collection and Monitoring Plan System</td>
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<td>EERS</td>
<td>Energy Efficiency Resource Standard</td>
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<td>EGU</td>
<td>Electric Generating Unit</td>
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<td>EIA</td>
<td>Energy Information Administration</td>
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<td>EM&amp;V</td>
<td>Evaluation, Measurement and Verification</td>
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<td>EO</td>
<td>Executive Order</td>
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<td>FR</td>
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<td>GHG</td>
<td>Greenhouse Gas</td>
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<td>GW</td>
<td>Gigawatt</td>
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<td>HAP</td>
<td>Hazardous Air Pollutant</td>
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<td>HRSG</td>
<td>Heat Recovery Steam Generator</td>
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<td>IGCC</td>
<td>Integrated Gasification Combined Cycle</td>
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<td>Intergovernmental Panel on Climate Change</td>
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<td>IPM</td>
<td>Integrated Planning Model</td>
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<td>IRP</td>
<td>Integrated Resource Plan</td>
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<td>ISO</td>
<td>Independent System Operator</td>
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<td>kWh</td>
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<tr>
<td>lb CO₂/MWh</td>
<td>Pounds of CO₂ per Megawatt-hour</td>
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<td>LBNL</td>
<td>Lawrence Berkeley National Laboratory</td>
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<tr>
<td>MMBtu</td>
<td>Million British Thermal Units</td>
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<td>NAAQS</td>
<td>National Ambient Air Quality Standards</td>
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<td>NAICS</td>
<td>North American Industry Classification System</td>
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<td>Commissioners</td>
<td>National Academy of Sciences</td>
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<td>NGCC</td>
<td>Natural Gas Combined Cycle</td>
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<td>New Source Review</td>
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<td>New York State Energy Research and Development Authority</td>
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<td>Office of Management and Budget</td>
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<td>Public Utilities Commission</td>
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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 use in developing plans to address greenhouse gas (GHG) emissions from existing fossil fuel-fired electric generating units (EGUs). Specifically, the EPA is proposing state-specific rate-based goals for carbon dioxide (CO₂) emissions from the power sector, as well as guidelines for states to use in developing plans to attain the state-specific goals. This rule, as proposed, would set in motion actions to lower the carbon intensity of power generation in the United States.

GHG pollution threatens Americans' health and welfare by leading to potentially rapid but long lasting changes in our climate that can have a range of severe negative effects on human health and the environment. CO₂ is the primary GHG pollutant, accounting for nearly three-quarters of global GHG emissions and 84 percent of U.S. GHG emissions.
Fossil fuel-fired EGUs are, by far, the largest emitters of GHGs, primarily in the form of CO₂, among stationary sources in the U.S. While much of the existing U.S. fleet of fossil fuel-fired EGUs began operations in the 20th century, advancements, innovation and changes in economics in power sector technologies, fuel sources and production, demand-side management, and energy efficiency are leading to changes in the way power is produced, distributed and used. The EPA believes that this confluence of factors in the electricity sector provides the basis for a rule under CAA section 111(d) by which states can develop and implement plans to reduce GHG emissions and lower the carbon intensity of the power sector by: 1) taking advantage of these changes, while ensuring a reliable supply of power at a reasonable cost; and 2) by mobilizing state leadership in developing any of a variety of sustainable energy strategies already being used by a number of States and companies in meeting the CO₂ goals set forth in this proposal.

In moving forward with those actions, states can rely on and extend plans they may already have underway to continue the development of their energy systems. Those states committed to Integrated Resource Planning (IRP) would be able to establish their plans within that framework to meet the CO₂ goals proposed here. At the same time, states would also be able to address the
economic interests of their utilities and ratepayers, by reducing costs and avoiding stranded asset risks using the flexibilities in this proposed action and working in concert with other states to put in place regional approaches reflecting the multi-state structure of electricity operating systems already critical to ensuring a reliable supply of affordable energy.

Under CAA section 111(d), 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 impact and energy requirements, the Administrator determines has been adequately demonstrated (BSER).\(^1\) Consistent with CAA section 111(d), the EPA is proposing state-specific goals that reflect the EPA’s calculation of the emission reductions that a state can cost-effectively achieve through the

\(^1\) 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; and the state is authorized to identify the standard(s) 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.
application of BSER.

While the EPA must establish BSER and is proposing goals that reflect BSER, CAA section 111(d) also provides the EPA with the flexibility to design guidelines that recognize, and can be tailored to, the uniqueness and complexity of the utility power sector and CO₂ emissions and that build upon the types of strategies many states and companies are already using today to reduce emissions of GHGs. At the same time, and importantly, CAA section 111(d) allows the states flexibility in designing the measures for their state plans in response to the EPA’s guidelines.

We emphasize that the purpose of the EPA’s determination of the BSER is simply to calculate the degree of emission limitation that the state plan must achieve. Each state may select any measure or combination of measures to achieve that emission limitation. States are not required to use each of the measures that the EPA determines constitute BSER or use those measures to the same degree of stringency that the EPA determines is achievable and cost-effective. Thus, a state could choose to achieve more reductions from one BSER measure and less from another or use measures that were not part of the EPA’s BSER determination, as long as the state achieves the reductions necessary to meet its goal.
This preamble sets forth the EPA’s proposal for BSER and guidelines for states to use in developing their plans. The preamble describes the EPA’s approach to determining BSER and setting state goals and lays out proposed expectations for state plans, along with discussion of other options that the EPA has considered. Additional detail on various aspects of the proposal is included in several technical support documents (TSDs), which are available in the rulemaking docket. The proposal was substantially informed by the input the EPA sought beginning in the summer of 2013. The EPA invites comment on all aspects of this proposal.

2. Summary of the major provisions

a. Approach

In developing this proposed rulemaking, the EPA is implementing provisions of the CAA that have been in place since Congress first enacted the modern CAA in 1970 and that ensure that in concert with the provisions of 110 and 112, new and existing major stationary sources address all major air pollutants. In this rulemaking, the EPA is following the regulatory requirements that have been in place since 1975 and that the EPA has followed in its previous CAA section 111(d) rulemakings for the past almost 40 years. These requirements call on the EPA to develop emission guidelines, which include
determining BSER. In general, the states must follow these
guidelines, including adhering to their stringency in requiring
emission reductions, in developing state plans. These
requirements authorize the EPA to develop emission reduction
goals based on the application of BSER to the states. In
following these provisions, the EPA is proposing a BSER based on
strategies currently being used by states and companies to
reduce CO₂ emissions from the power sector.²

The CAA identifies the factors for the EPA to consider in a
BSER determination and, for this rulemaking, the following
factors are key: technical feasibility, costs, size of emission
reductions and technology (i.e., whether the system promotes the
implementation and further development of technology). To
determine BSER, the EPA considered the reductions achievable
through the two basic types of approaches to reducing CO₂
emissions from existing fossil fuel-fired EGUs: making emission
rate improvements at affected EGUs (e.g., by improving heat
rates or switching to lower carbon fuels) and limiting emissions
of the fossil fuel-fired EGU category as a whole (e.g., by
shifting dispatch from higher carbon-emitting EGUs to lower
carbon-emitting EGUs and by employing demand-side energy

² [Insert example of allowing gas clean up instead of flaring for
landfills emission guidelines. This strategy was already being
used before we promulgated the rule).]
efficiency strategies that provide the same services with less electricity). As the EPA has done in making BSER determinations in the past, the agency considered the types of strategies that states and companies are already employing to reduce CO₂ emissions from fossil fuel-fired EGUs. For example, 10 states have market-based GHG emission programs, 29 states have implemented renewable portfolio standards, and utilities in 48 states run demand-side energy efficiency programs. Such strategies and the proposed BSER determination reflect the fact that, in almost all states, the production of electricity can be undertaken, at least to some extent, interchangeably between and among multiple generation facilities and different types of generation. As a result, the agency, in quantifying state goals (and the states in devising plans to meet those goals) can assess what combination of electricity production, or energy demand reduction, across generation facilities can offer the most cost-effective approach to achieving GHG emission reductions. States, in turn, can look broadly at opportunities across their electricity system to meet their goals. Importantly, states may rely on measures that they already have in place, including reduced utilization as a method for reducing CO₂ emissions from individual existing EGUs, to the extent that those measures help meet the goals.
To determine BSER for reducing CO₂ emissions at affected EGUs, and to establish the numerical goals that reflect BSER, the EPA considered numerous measures that can and are being implemented to improve emission rates and to limit overall CO₂ emissions from fossil fuel-fired EGUs. These measures can be grouped into four main categories, or “building blocks,” both for formulating state goals and for constructing broad-based, cost-effective, long-term strategies to reduce CO₂ emissions on the part of the states. In this preamble, The EPA believes explains that each of the building blocks represents a method of CO₂ emission reduction at fossil fuel-fired EGUs that, when combined with the other building blocks, represent the “best system of emission reduction... adequately demonstrated” for fossil-fuel-fired EGUs. The building blocks are:

1. Lowering the carbon intensity of generation at individual affected EGUs (e.g., through heat rate improvements);
2. Reducing emissions of the most carbon-intensive affected EGUs to the extent that this can be accomplished by cost-effectively by shifting generation to less carbon-intensive existing fossil fuel-fired EGUs, including NGCC units that are under construction;
3. Reducing emissions of carbon-emitting EGUs to the extent that this can be accomplished by cost-effectively by expanding the amount of new, lower (or no) carbon-intensity generation; and,

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

The four building blocks are described in detail in Sections VI and VII of this preamble.

The EPA believes that the BSER for purposes of CAA section 111(d), as applied to the sources in the power sector, is a combination of measures that reduce CO₂ emissions and CO₂ emission rates and which reflect or encompass all four building blocks. A range of amounts of reductions can be achieved by application of each building block; in determining BSER, we have considered these ranges, in light of statutory factors, and we have identified goals that we feel best satisfy those criteria. Relying on all four building blocks to characterize the combination of measures that reduce CO₂ emissions and CO₂ emission rates at affected EGUs as BSER is consistent with strategies that companies and states are already taking 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 meaningful, cost-effective, and technically feasible reductions of CO₂, and promotes technology and approaches that are important for achieving further reductions, all while providing the states with a balance of flexibility and direction.

Recognizing that states differ in important ways, including in their mix of existing EGUs, and consequently that their opportunities to reduce EGUs’ emission rates and limit each EGU’s overall emissions, as reflected in each of the application of the building blocks, vary across states, and the EPA has applied the elements of BSER to the circumstances of individual states by considering state-specific data in order to determine state-specific goals.

This use of building blocks aligns with key messages from stakeholders provided during the EPA’s recent and extensive public outreach process, notably the desire for flexibility and recognition of varying state circumstances. The state-specific approach 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 CO₂ 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. They may also identify technologies and/or strategies not explicitly spelled out in any of the four building blocks and use those technologies and/or strategies as part of their overall plan. This approach also allows regional compliance strategies. The agency also recognizes the important functional relationship between the timing of measures and their stringency. Because the EPA is proposing a 10-year period over (2020 – 2030) over which to achieve the full required CO₂ reductions, 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 timely and cost-effective manner.

b. State goals and flexibilities

In this action, the EPA is proposing state-specific rate-based goals to guide states in the development of their plans. These state-specific goals are based on an assessment of the amount of emissions that can be reduced at high-emitting facilities through application of BSER, as contemplated and required under CAA section 111. For this purpose, we used the most recent available information, including data on generation...
capacity and availability at existing generation facilities and those generation facilities currently being built. The agency is proposing state-specific interim and final goals that must be achieved by no later than the year 2030. The proposed final goals reflect the EPA’s quantification of state-average emission rates from affected EGUs that could be achieved by 2030 and sustained thereafter. The proposed interim goals would apply over a 2020-2029 phase-in period. The proposed final goals reflect the EPA’s quantifications of adjusted state-average emission rates from affected EGUs that could be cost-effectively achieved cumulatively or on average over the respective plan period through implementation of the four building blocks described above to achieve reductions in overall CO₂ emissions at affected EGUs. The proposed state-specific goals are intended to demonstrate the level of reductions in CO₂ emissions and emission rates and the level of stringency of the application of the building blocks that would be presumptively approvable in a state plan.

A state must submit a plan documenting how it will achieve an emission performance level equivalent to the state-specific goal set by the EPA. The state may choose the measures to achieve its goal. If the state determines that the application of certain measures yields fewer reductions is preferable to than...
the EPA’s approach, then it may use other or additional measures to achieve the required reductions.

The EPA is proposing to allow each state flexibility with regard to the form of the goal. Under this proposal, a state would not be obligated to adopt the rate-based form of the goal established by the EPA. A state plan submittal reflecting a mass-based form of the goal or a regional approach based upon either rate or mass would be approvable based upon a demonstration that the submittal is equivalent in stringency, including timing, to the state-specific rate-based goal set by the EPA.

We believe that this approach to establishing requirements for state plans is responsive 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, in the context of the diverse and highly interconnected electric industry, between two competing objectives grounded in CAA section 111(d) – a need for rigor and consistency in calculating the amount of required emission reductions, and a need for flexibility in establishing and implementing the standards of performance that reflect those emission reductions. We view the proposed goals as providing

Comment [A11]: As written it implies that only if EPA’s approach over predicted reductions can they use something else, but I think you mean to say is that states can do whatever they like as long as they hit the target (or exceed it, ie greater reductions).
rigor where rigor is required by the statute, while providing states with flexibility where flexibility is permitted by the statute. This approach is also 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. It further reflects and is based on the growing trend, as exemplified by many state and local clean energy policies and programs, to shift our energy production away from carbon-intensive fuels to a more sustainable system that puts greater reliance on renewable energy, energy efficiency, and demand-side management.

c. State plans
i. Approach

Each state would determine, and include in its plan, an emission performance level that is equivalent to the state-specific CO₂ goals in the emission guidelines. As part of determining this level, the state would 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.

In this action, the EPA is proposing emission guidelines that, in addition to establishing the state-specific goals, include approvability criteria, requirements for state plan components, and requirements for the process and timing for state plan submittal and achievement of the CO₂ 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 emission 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-only or regional approaches that can be achieved on either a rate or mass basis. They also address several key policy considerations that states will have to address 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 the portfolio approach. In view of legal issues concerning state plan structure, under CAA section 111(d)(1), discussed below, the EPA is soliciting comment on a different approach for state plans, which is that CO2 emission limits that apply directly to the affected EGUs must assure achievement of the entire amount of the emission performance level.

ii. State plan components

The EPA is proposing to evaluate and approve each of the ten components of a state plan based on four general criteria: 1) enforceable measures that reduce EGU CO2 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 CO2 goals, and implementation of corrective actions, if necessary. In addition, each state plan must follow the EPA framework regulations at 40 C.F.R. 60.23 – 60.29 and include the following twelve components for the EPA to evaluate and approve the plan:

- Identification of affected entities
- Description of plan approach and geographic scope

Comment [A14]: We recommend EPA start this by listing the components (and is it 10 or 12) and then provide/explain these approval criteria.
iii. Process for state plan submittal and review

In accordance with the President’s Climate Action Plan, the EPA expects to finalize this rulemaking by June 1, 2015. The Climate Action Plan 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, which is about one year after promulgation of the final emission guidelines, instead of the 9 months specified in the EPA framework regulations at 40 C.F.R. 60.23. However, the EPA recognizes that some states may need more than one year to develop a final state plan in order to provide sufficient time for technical work, state legislative and rulemaking schedules, coordination with third parties, and coordination among states involved in multi-state plans. Therefore, the EPA is proposing a two-phased submittal process for state plans as an option. Each state would be required to submit its plan by June 30, 2016.

Comment [A15]: Why included? Surplus to what?

Comment [A16]: Suggest deleting; it’s confusing, and the implementing regs explain that this time frame can be longer (additionally, the statute specifies no time frame).
However, if a state needs additional time, then the state may submit an initial plan by June 30, 2016. This initial plan must meet specific criteria for approval, including a justification for why more time is needed, a requirement to maintain existing measures that limit CO₂ emissions, and an explanation of the path to completion.

If the initial plan includes those components, the EPA will approve the initial plan and provide an extension of time to submit a complete plan. In this case, the state would have until June 30, 2017, to submit a complete plan if the geographic scope of the plan is limited to that state. However, if the state develops a plan that includes a multi-state approach, then 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, and the potential complexity of the plans the EPA anticipates receiving, the EPA is proposing to extend the period of the EPA review of plans from the 4-month period provided in the EPA framework regulations to 6 months.

**Comment [A17]:** How often has EPA finished review in 4 months of NAAQS SIPs? Further, what happens if EPA doesn’t finish in 6 months – do states assume their plans have been approved?
v. Timing of compliance

The agency is proposing that states must achieve compliance with the CO₂ emission performance level in the state plan by no later than 2030. Under this proposed option, a state would need to meet an interim CO₂ emission performance level on average over the 10-year period from 2020-2029, as well as achieve its final CO₂ 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 would best support the optimization of overall CO₂ reductions. The agency is also requesting comment on two alternative options fully described in section VIII of this preamble.

vi. Key considerations for state plans

There are a number of considerations with which states will be faced in developing their plans and ensuring that they meet the general approvability criteria. Each state will have to make decisions, for example, on: 1) whether it will use the state-specific rate-based goal established by the EPA or will instead use an equivalent mass-based form of the goal; 2) which type of state plan approach best fits the state’s circumstances; 3) which types of measures will be included in its plan; 4) what
types of demand-side reduction measures should the state put in place; and, 5) when various measures will yield reductions.

The EPA addresses these and other considerations in this proposal and is seeking comment on the options presented, as well as alternatives.

vii. 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, has collected available resources and is making these available at an EPA website.3

3 [Add address for the EPA website]

3. Projected national-level emission reductions

Under the proposed rule, the EPA projects annual CO₂ reductions of 25 to 30 percent below 2005 levels (ranges reflect ongoing evaluation of building block 3 alternatives, and the rest of the preamble is being modified to reflect these ranges).

4. Costs and benefits

Actions taken to comply with the proposed guidelines will reduce CO₂ emissions from the electric power industry, as well as other fossil-fuel-fired EGU emissions including directly emitted
fine particulate matter (PM_{2.5}), sulfur dioxide (SO_2) and nitrogen oxides (NO_x). 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 estimates that, in 2020, this proposal will yield monetized climate and air pollution health co-benefits of $20 to $40 billion (2011$). The annual compliance costs of this proposal range from $5 to $10 billion (2011$) in 2020. It will achieve emission reductions of approximately 25% to 30% between 2020 and 2030. These estimates are preliminary and subject to change.

It is important to also note that there are benefits that the EPA could not monetize. The EPA could not monetize important benefits. 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.

Based upon the foregoing estimates outlined above, 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, 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, followed by identification of affected sources and the proposed treatment of source categories in Section V. 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 goals and the proposed requirements for state plans, respectively. Implications for the new source review and Title V programs are described in Section IX, and impacts of the proposed action are described in Section X. A discussion of statutory and executive order reviews is provided in Section XI, and the statutory authority for this action is provided in Section XII.
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 CO2 emissions from new affected sources, and the rulemaking for modified and reconstructed sources that the EPA is proposing at the same time as the present 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 anything 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 we refer to as the Endangerment Finding under CAA section 202(a)(1).\(^4\) 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

   Anthropogenic emissions of GHGs and consequent climate change threaten public health in multiple ways. By raising average temperatures, climate change increases the likelihood of heat waves, which are associated with increased deaths and illnesses. While climate change also increases the likelihood of reductions in cold-related mortality in some areas of the (world or the US?), evidence indicates that globally the increases in heat mortality will be larger than the decreases in cold mortality. It is predicted that increased temperatures will lead to increases in ozone pollution over broad areas of the U.S., including large population areas with already unhealthy surface ozone levels are already above the NAAQS, and thereby increase the risk of morbidity and mortality. Other public health threats also stem from estimates

Comment [A27]: Please be specific when you are referring to global vs. US specific changes (and thus impacts).

Comment [A28]: The tone of this write up and the similar one in the RIA loses the nuance of the Findings For instance, compare conclusiveness of the word choices with http://www.epa.gov/climatechange/Downloads/endangerment/EndangermentFinding_Health.pdf

Comment [A29]: Pls specify the scope of the discussion.
of 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 risks.

2. Public welfare impacts detailed in the 2009 Endangerment Finding

Anthropogenic emissions of GHGs and consequent climate change also threaten public welfare in multiple aspects. 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

Comment [A31]: Let’s discuss – specifically why these were chosen, if this is exhaustive, the rigor of peer review for each, and how EPA is characterizing new studies.
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 Working Group I contribution to the 2013 Fifth Assessment Report (AR5), and the NRC’s 2010 “Ocean Acidification: A National Strategy to Meet the Challenges of a Changing Ocean” (Ocean Acidification), 2011 “Report on Climate Stabilization Targets: Emissions, Concentrations, and Impacts over Decades to Millennia” (Climate Stabilization Targets), 2011 “National Security Implications for U.S. Naval Forces” (National Security Implications), 2011 “Understanding Earth’s Deep Past: Lessons for Our Climate Future” (Understanding Earth’s Deep Past), 2012 “Sea Level Rise for the Coasts of California, Oregon, and Washington: Past, Present, and Future”, 2012 “Climate and Social Stress: Implications for Security Analysis” (Climate and Social Stress), and 2013 “Abrupt Impacts of Climate Change” (Abrupt Impacts) assessments.

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

In addition, these assessments highlight the urgency of the situation as the concentration of CO₂ in the atmosphere continues to rise. Absent a reduction in emissions, a recent 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.⁵

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.”⁶

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 millenia.\textsuperscript{7}

Moreover, due to the time-lags inherent in the Earth’s
climate, the NRC assessment notes that the full warming from any
given concentration of CO\textsubscript{2} reached will not be realized for
several centuries.

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.
At the time of the 2009 Endangerment Finding, the concentration
of carbon dioxide was 387 parts per million.\textsuperscript{8} As of the date of

\textsuperscript{7} National Research Council, Climate Stabilization Targets,
p. 3.

\textsuperscript{8} ftp://aftp.cmdl.noaa.gov/products/trends/co2/co2_annmean_mlo.txt
signature of this proposed rulemaking, the concentration is [XX – likely higher than 398] parts per million.\(^9\)

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\(^{10}\) (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 1 below, which presents total U.S. anthropogenic emissions and sinks\(^{11}\) of GHGs, including CO\(_2\) emissions, for the years 1990, 2005 and 2012.

\(^9\) http://www.esrl.noaa.gov/gmd/ccgg/trends/
http://epa.gov/climatechange/ghgemissions/usinventoryreport.html
\(^{11}\) Sinks are a physical unit or process that stores GHGs, such as forests or underground or deep sea reservoirs of carbon dioxide.
Table 1. U.S. GHG Emissions and Sinks by Sector (teragram carbon dioxide equivalent (Tg CO₂ Eq.))

<table>
<thead>
<tr>
<th>SECTOR</th>
<th>1990</th>
<th>2005</th>
<th>2012</th>
</tr>
</thead>
<tbody>
<tr>
<td>Energy</td>
<td>5,256.5</td>
<td>6,239.4</td>
<td>5,489.6</td>
</tr>
<tr>
<td>Industrial Processes</td>
<td>316.1</td>
<td>330.2</td>
<td>319.6</td>
</tr>
<tr>
<td>Solvent and Other Product Use</td>
<td>4.4</td>
<td>4.4</td>
<td>4.4</td>
</tr>
<tr>
<td>Agriculture</td>
<td>473.9</td>
<td>512.2</td>
<td>526.3</td>
</tr>
<tr>
<td>Land Use, Land-Use Change and Forestry</td>
<td>13.7</td>
<td>25.5</td>
<td>37.8</td>
</tr>
<tr>
<td>Waste</td>
<td>165.0</td>
<td>133.2</td>
<td>124.0</td>
</tr>
<tr>
<td>Total Emissions</td>
<td>6,229.6</td>
<td>7,244.9</td>
<td>6,501.5</td>
</tr>
<tr>
<td>Land Use, Land-Use Change and Forestry (Sinks)</td>
<td>(831.3)</td>
<td>(1,030.7)</td>
<td>(979.4)</td>
</tr>
<tr>
<td>Net Emissions (Sources and Sinks)</td>
<td>5,398.5</td>
<td>6,214.2</td>
<td>5,522.1</td>
</tr>
</tbody>
</table>

Total fossil energy-related CO₂ emissions (including both stationary and mobile sources) are the largest contributor to total U.S. GHG emissions, representing 77.9 percent of total 2012 GHG emissions. In 2012, fossil fuel combustion by the electric power sector -- entities that burn fossil fuel and whose primary business is the generation of electricity --

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accounted for 38.7 percent of all energy-related CO₂ emissions.

Table 2 below presents total CO₂ emissions from fossil fuel-fired EGUs, for years 1990, 2005 and 2012.

**Table 2. U.S. GHG Emissions from Generation of Electricity from Combustion of Fossil Fuels (Tg CO₂ Eq.)**

<table>
<thead>
<tr>
<th>GHG EMISSIONS</th>
<th>1990</th>
<th>2005</th>
<th>2012</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total CO₂ from fossil fuel combustion EGUs</td>
<td>1,820.8</td>
<td>2,402.1</td>
<td>2,023.6</td>
</tr>
<tr>
<td>- from coal</td>
<td>1,547.6</td>
<td>1,983.8</td>
<td>1,512.2</td>
</tr>
<tr>
<td>- from natural gas</td>
<td>175.3</td>
<td>318.8</td>
<td>492.2</td>
</tr>
<tr>
<td>- from petroleum</td>
<td>97.5</td>
<td>99.2</td>
<td>18.8</td>
</tr>
</tbody>
</table>

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. Currently, the majority over 50% of power in the U.S. is generated from the combustion of coal, natural gas, and other fossil fuels. In recent years, though, the proportion of new renewable generation coming on line has increased dramatically. For instance, one-third of new generating capacity built in 2013 used renewable power generation technologies (EIA, 2014).

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 CO2 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 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.” EPA has listed more than 60 stationary
source categories under this provision. Once EPA lists a source
category, 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. These standards are
known as new source standards of performance (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 section 111(d) contemplates states

13 CAA §111(b)(1)(A).
14 See 40 CFR 60 subparts Cb – OOOO.
15 CAA §111(b)(1)(B), 111(a)(1).
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.”16 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.17 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. In the case of a tribe that

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16 CAA section 111(d)(2)(A).
17 CAA section 111(d)(2)(A).
has one or more affected EGUs on its lands, the tribe would have the opportunity, but not the obligation, to establish a CO₂ performance standard and a plan for its tribal lands.

The EPA issued regulations implementing CAA section 111(d) in 1975, and has revised them in the years since. (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. 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, and the EPA must take final action on the state plans within 4

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18 The EPA is aware of at least three affected sources located in Indian Country located in Indian Country, two on [Navajo] lands – the Navajo Generating Station and the Four Corners Generating Station – and one on [Ute] lands – the Bonanza Generating Station. All three are coal-fired EGUs.


20 [Cites]

21 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 Fed. Reg. at 53,343.

22 40 CFR 60.23(a)(2).
months of the due date for those plans,\(^{23}\) although the EPA has authority to extend those deadlines.\(^{24}\) 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)).\(^{25}\) In addition, the agency has regulated additional pollutants under CAA section 111(d) in conjunction with CAA section 129.\(^{26}\) 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 towards the pollutants and industries regulated. Similarly, in the present rulemaking, in defining CAA section 111(d) goals and guidelines for the states, the EPA believes it is necessary to take into account the particular

\(^{23}\) 40 CFR 60.27(b).
\(^{24}\) See 40 CFR 60.27(a).
\(^{25}\) \[Cites\]
\(^{26}\) \[Cites\]
characteristics of carbon pollution and the interconnected nature of the power sector, especially the fact that increments of generation are 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 CO₂ emissions. Doing so results in a broader, forward-thinking approach to the design of programs to yield critical CO₂ reductions that improve the overall power system by lowering the carbon intensity of power generation, while offering continued reliability and cost-effectiveness.

In this action, the EPA is proposing emission guidelines for states to use in developing their plans to reduce emissions of CO₂ 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 President in a Memorandum to the Administrator (June 25, 2013), 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 February 2013, the presentation had been viewed more than 4,400 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 - a new email account: carbonpollutioninput@epa.gov; and a web-based form: http://www2.epa.gov/carbon-pollution-standards/forms/carbon-pollution-standards-contact-us. These links, along with policy, program, and technical information about this rulemaking effort, are available on the EPA’s website at: http://www2.epa.gov/carbon-pollution-standards. 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
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 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. The EPA has taken information from these meetings and used it to inform this proposal. 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 a dialog with states and stakeholders will continue 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 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 may benefit from 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 located in Indian country but is not aware of any power plants 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. Due to the focus of the standard 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, including outreach to the National Environmental Justice Advisory Committee members in September 2014.

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

A number of labor unions invited EPA officials to their meetings to give presentations and engage in discussions about reducing carbon pollution using CAA section 111(d). EPA staff met with union representatives that included the United Mine Workers of America, the International Brotherhood of Boilermakers, Iron Ship Builders, Blacksmiths, Forgers and Helpers, United Association, the International Brotherhood of Electrical Workers, the Utility Workers Union of America have participated in meetings at the EPA. In addition, agency leaders participated in a meeting of the Presidents of several unions at the AFL-CIO.

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 only 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. 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 legally responsibility for the full amount of required CO₂ 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 CO₂ 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 due to 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 CO₂ 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 there were a number of ideas that were put forward that are not fully reflected in this proposal. We invite public comment on the ideas. These ideas include those outlined below.

1. Model rule on interstate emissions credit trading and price ceiling
Some groups thought that 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, a demonstration that the state program achieves equivalent or better carbon intensity for the regulated sector; mass-based equivalency, a demonstration that the program achieves equal or greater emission reductions relative to what would be archived by the federal approach; or a market price-based equivalency, 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.
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. They indicate that once plant-specific goals are established based on on-site CO2 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.

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-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.

1. Market-based emission limits

Nine states actively participate in the Regional Greenhouse Gas Initiative (RGGI), a market-based CO₂ emission reduction program addressing EGUs that was established in 2009.²⁷ Through RGGI, the participating states are implementing coordinated CO₂ emission budget trading programs. In aggregate, these programs establish an overall limit on allowable CO₂ emissions from affected EGUs in the participating states. Participating states issue CO₂ 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 CO₂ allowances equal to their reported CO₂ emissions. CO₂ allowances may be traded among both regulated and non-regulated parties, creating a market for emission allowances. This market creates a price signal for CO₂ emissions, which factors into the dispatch of affected EGUs. A price signal for CO₂ emissions also allows sources flexibility to make emission reductions where reduction

²⁷ The nine states include Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont.
costs are lowest, and encourages innovation in developing emission control strategies.

Approximately 90 percent of CO₂ allowances are distributed by the RGGI participating states through auction. 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 CO₂ emissions. Through 2012, for example, the RGGI states invested approximately $460 million of proceeds into energy efficiency programs. 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.

Between 2005, when an agreement to implement RGGI was announced, and 2012, power sector CO₂ emissions in the RGGI

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31 Ibid.
participating states fell by more than 40 percent. In January 2014, the participating states lowered the overall allowable CO₂ emission level in 2014 by 45 percent, setting a multi-state CO₂ emission limit for affected EGUs of 91 million short tons of CO₂ in 2014 and 78 million short tons of CO₂ in 2020, more than 50 percent below 2008 levels.

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. 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 CO₂ equivalent by 2025, a 25 percent reduction

33 The first three-year control period under RGGI, establishing CO₂ emission limits for EGUs, began on January 1, 2009.

Comment [A48]: The statement regarding the reductions in power sector CO₂ emissions exceeding 40 percent in the RGGI states between 2005 and 2012 may open the draft preamble to criticism by appearing to suggest that the RGGI program was actually an important causal factor in that reduction. It is commonly understood that RGGI program was largely non-binding during this period, with emissions well below the program’s cap. The concern can be addressed through additional language indicating that RGGI was not the primary driver of the observed regional trend in power sector CO₂ emissions.
from 2005 power sector emission levels. Prior to the implementation of the emission trading program, California reports that it reduced CO₂ power sector emissions by 16 percent from 2005 to a 2010-2012 averaging period, a reduction of 16 million metric tons of CO₂ equivalent.

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 CO₂/Megawatt hour (MWh) (based on output) or 120 pounds of CO₂/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 CO₂/MWh (based on output) or 160 pounds of CO₂/MMBtu (based on input).

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37 Ibid.

38 6 New York CoCodes, Rules & Regulations. Part 251 (Adopted June 28, 2012)
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 CO2 emission rate of 1,100 pounds of CO2 per MWh or less.\(^{39}\)

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. 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

\(^{39}\) OR SB 101 (2000); Washington Revised Code ch.80.80 (2013); Wash SB 6001 (2007)
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 by 28 percent by 2020.\textsuperscript{40}

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. 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 electricity generating units, 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.\textsuperscript{41} The 2012 requirement increased to 18 percent of total retail sales for Xcel Energy and 12 percent for all other utilities.\textsuperscript{42} 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.\textsuperscript{43}

\textsuperscript{42} Ibid.
\textsuperscript{43} HF 729, https://www.revisor.mn.gov/laws/?id=85&doctype=Chapter&year=2013&type=0#laws.10.3.0
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 load 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 2012.44

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. These 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

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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 CO2 allowance auction proceeds mentioned above.

Nationally, total spending on electric ratepayer-funded energy efficiency programs was $5.9 billion in 2010. Based on Lawrence Berkeley National Laboratory (LBNL) projections, spending is projected to reach $8.1 billion in 2025.46


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.\footnote{American Council for an Energy Efficient Economy (ACEEE) 2013 State Scorecard http://www.aceee.org/sites/default/files/publications/researchreports/e13k.pdf}\footnote{December 27, 2013 Letter from Mary D. Nichols, Chairman of California Air Resources Board, to EPA Administrator Gina McCarthy.} 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.”\footnote{Dec. 27, 2013 Letter from Mary D. Nichols, Chairman of California Air Resources Board, to EPA Administrator Gina McCarthy.} 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.”\footnote{Cal. Pub. Utility Code §454.5 (a)(9)(C).} 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.\textsuperscript{50} 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.”\textsuperscript{51} Between 2010 and 2011, California estimates that their demand-side energy efficiency programs reduced CO\textsubscript{2} by 3.8 million tons.\textsuperscript{52}

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.\textsuperscript{53} 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.\textsuperscript{54} In 2012, Efficiency Vermont, the PSB-appointed energy efficiency utility, achieved annual savings of 1.9 percent of the state’s electricity sales, at a cost of 3.5 cents per kilowatt-hour, lower than the cost of comparable electric supply

\textsuperscript{50} Cited in December 27, 2013 Letter from Mary D. Nichols, Chairman of California Air Resources Board, to EPA Administrator Gina McCarthy.
\textsuperscript{51} Ibid.
\textsuperscript{52} Ibid.
\textsuperscript{53} http://psb.vermont.gov/utilityindustries/eeu/generalinfo/creationandstructure
\textsuperscript{54} [Insert link to Law]
in the same year, which was 8.6 cents per kWh. Efficiency Vermont projects a net lifetime economic value to Vermont of more than $100 million from the 2012 energy efficiency investments.

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. 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-fired EGU generation through reductions in electricity demand, thereby reducing CO₂ 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. The rule required utilities to achieve 1.25 percent electricity savings in 2011 compared to electricity sales in the previous

56 Ibid.
year, ramping up the savings each year until 2020 according to a designated timetable. 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). 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. 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.

E. Conclusions

States have taken a leadership role in mitigating GHG emissions and have demonstrated the potential for national

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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 improve the efficiency of fossil-fired EGUs, but also reduce their utilization through taking advantage of opportunities for lower-emitting generation and reduced electricity demand across the electricity system.

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 the state having the flexibility to design a cost-effective program tailored to its own specific circumstances. The agency also recognizes, as many states 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 CO₂ 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" (BSER) 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
emission reductions that a state can achieve through the cost-effective application of 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 the emission performance level it will include in its plan by deciding whether it will adopt the rate-based CO\textsubscript{2} goal set by the EPA or translate the rate-based goal into 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 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 “best system of emission reduction ... adequately demonstrated” (BSER) as the combination of emission rate improvements and limitations on overall emissions at affected EGUs that can be accomplished through the following four sets of measures, or building blocks:

1. Lowering the carbon intensity of generation at individual affected EGUs (e.g., through heat rate improvements).
2. Reducing utilization of the most carbon-intensive affected EGUs to the extent that this can be accomplished
3. Reducing emissions of affected carbon-emitting EGU’s to the extent that this can be accomplished cost-effectively by expanding the amount of new, lower (or no) carbon-intensity generation.

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

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 EGU’s 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 up to a 70 percent utilization rate; block 3, including nuclear units under construction, avoiding retirement of about eight percent of existing nuclear capacity, and increasing renewable electricity generation 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

Comment [A59]: Might want to add “and reliably”

Comment [A60]: What about at NG units?

Comment [A61]: The discussion of RE potential appears inconsistent with discussion of other technologies. RE costs should be considered, as RE is now cost-competitive in many states, which may suggest additional potential, consistent with an all-of-the-above approach.
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 amount of 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 further proposing, as part of the emission 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. This would either be a complete plan or, if justified, an initial plan that describes why additional time is needed and documents the state’s progress in preparing a complete plan. A state that submits an initial plan with the proper components will receive an extension of time to submit a complete plan. 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 the states the option of translating the EPA-determined goal, which will be rate-based, to a mass-based goal. The EPA is also proposing that the 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 emission guidelines, to authorize the state to submit either of two types of measures to achieve the performance level: (i) emission limitations that apply directly to the affected sources, and (ii) a set of measures that we refer to as “portfolio” measures, which include emission limitations that apply directly to the affected sources as well as other measures that have the effect of limiting generation by, and therefore emissions from, the affected sources.

The EPA is also proposing, as part of its emission
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, surplus, 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 CO₂ 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 CO₂ goals, and implementation of corrective actions, if necessary.

The EPA is also proposing, as part of its emission guidelines, requirements for the timing for implementation and achievement of the required level of emission performance,
including performance and emission milestones. The proposed option would require each state to achieve its ultimate CO₂ 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 CO₂ emission performance level on average over the 10-year phase-in compliance period and also achieve its ultimate CO₂ 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 on its lands, the tribe would have the opportunity, but not the obligation, to adopt a plan for its tribal lands that establishes CO₂ performance standards.

B. Summary of Legal Basis

Comment [A67]: Suggest adding a brief mention of the fact that EPA would require check-ins along the way to ensure that states are on track to meet the interim and final targets.

Comment [A68]: If a tribe chose not to do a plan, would no standards apply to facilities on those lands? If legally unclear, is this something that EPA would want to take comment on?

The EPA is aware of at least three affected sources located in Indian Country located in Indian Country, two on [Navajo] lands - the Navajo Generating Station and the Four Corners Generating Station - and one on [Ute] lands - the Bonanza Generating Station. All three are coal-fired EGUs.
The EPA believes that today’s proposed action is consistent with the requirements of CAA section 111(d) and the framework regulations. As an initial matter, the EPA reasonably interprets the ambiguous provisions concerning the air pollutants covered under CAA section 111(d) to authorize the EPA to regulate CO₂ from EGUs. Moreover, although CAA section 111(d) applies only to sources that, if they were new sources, would be covered under a CAA section 111(b) rule, the EPA intends to complete the CAA section 111(b) rulemaking regulating CO₂ from new EGUs, and that rulemaking 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 framework regulations, the EPA explicitly stated that it is authorized to determine BSER, and the EPA is not re-opening that interpretation in this rulemaking. Accordingly, in this rulemaking, the EPA is determining BSER.

The four building blocks include two types of measures that, together, comprise BSER for fossil-fired EGUs. Building block 1 provides the basis for identifying carbon intensity improvements as a component of BSER. Building blocks 2, 3, and 4 provide the foundation for applying limitations in utilization.
to limit mass emissions at these EGUs. The EPA reasonably identified both types of measures as components of BSER based on the factors that the EPA is required to consider and the EPA’s authority to weigh those factors.

In addition, the measures in building blocks 2, 3, and 4 may be viewed as separate measures that reduce emissions by replacing the demand for generation at coal-fired EGUs. Because of the integration of the electricity system and the fungibility of electricity, these measures must be considered part of the system of emission reduction for fossil-fired EGUs.

Moreover, the measures in each of the building blocks are “adequately demonstrated,” including being technically feasible. Heat rate improvement measures are well-recognized as feasible within the industry. The measures that entail dispatch changes from coal-fired EGUs to NGCC units, investments in renewable energy, and demand-side energy efficiency 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-fired EGUs. Further, all of the measures achieve an important degree of emission reduction. In addition, they are not unreasonably costly, particularly when considered on the level of the nation’s electricity system. Importantly, the measures encourage the development and expansion of technology.
and practices to reduce CO₂ and are consistent with current trends in the electricity sector.

After determining BSER, the EPA is authorized under the framework regulations, as an integral component to setting emission guidelines, to apply the BSER to each state and determine the resulting emission limitation for each state.

With the promulgation of the emission guidelines, each state must develop a plan to achieve its emission performance level. The state plans must establish standards of performance and include measures that implement and enforce those measures.

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 emissions performance level, but instead impose requirements on other affected entities - such as renewable energy sources and demand-side energy efficiency measures - that would reduce utilization of, and therefore CO₂ emissions from, the affected EGUs. It could be argued that those requirements on other affected entities may be authorized as standards of performance or implementing measures, but the EPA acknowledges the legal uncertainty, since those sources do not emit CO₂. As a result, the EPA also solicits comment on whether state plans must could impose all of the legal responsibility for achieving...
the emissions performance level on the affected EGUs. If so, the state plan could nevertheless include the requirements on other affected entities in order to facilitate the reduced utilization of, CO₂ emissions from, the affected EGUs. We emphasize that the states have discretion as to the form of the standards of performance and may include emission trading programs.

To comply with the applicable standards of performance, sources may rely on any means of emission reduction, regardless of whether the EPA identifies those measures as part of BSER.

In this rulemaking, the EPA proposes reasonable deadlines for state plan submission and the EPA’s action. The proposed deadlines vary from those in the framework regulations.

V. Authority to Regulate Carbon Dioxide, Affected Sources, Treatment of Categories

A. Authority to Regulate Carbon Dioxide

The EPA has the authority to regulate, under CAA section 111(d), CO₂ 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 §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, §111(d)(1) requires states to submit standards of performance for existing sources “for any air pollutant (i) for which air quality criteria have not been issued or which is not included on a list published under [CAA] section 108(a)... [or emitted from a source category which is regulated under section 112] [61] [or 112(b)] [62]... ” The bracketed and emphasized provisions set forth the House and Senate versions, respectively. 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 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

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power plants” was premised on the Court’s understanding that section 111, including section 111(d), applies to carbon dioxide emissions from those sources.

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

### B. 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 1429; 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; (3) sells the greater of 219,000 MWh per year or 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

Comment [A79]: Might be outside the scope of this proposal – but what about reciprocating gas engines that are used to generate power? Each engine may deliver <20 MW of electricity, but these engines are typically stacked in a plant to yield >100 MW of electricity – there would be emissions associated with these engines that might need to be accounted for?

Comment [A80]: EPA should clarify whether or not the emissions from a plant that operates at full capacity for four months of the year are included in emissions calculations for the purposes of state compliance.
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 over rolling three-year periods (or as long as the unit has been in operation, if less).

The rationale for the proposals concerning applicability are the same as 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.

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

In this rulemaking, the EPA is co-proposing 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 co-proposing codifying all of the proposed requirements for the affected EGUs new subpart UUUU of 40 CFR part 60.

As discussed in the 2014 proposal for 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 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 CO₂ 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 was 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 co-proposing to combine the two categories into a single category for purposes of the CO₂ 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 CO₂ 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 co-proposing two options for codifying the emission guidelines for affected sources. Under the first option, the EPA is proposing to codify the standards of performance for the respective sources within existing 40 CFR part 60 subparts: subpart Da, electric utility steam generating units, which includes steam electric utility boilers and IGCC units, and subpart KKKK, stationary combustion turbines, which includes both simple cycle and combined cycle stationary combustion turbines. Emission guidelines for electric utility steam generating units would be included in subpart Da and
emission guidelines for stationary combustion turbines would be included in subpart KKKK.

Under the second option, 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.

We solicit comment on the relative merits of each approach. In particular, we seek comment on whether the co-proposal to combine the categories and codify the GHG emission guidelines for all existing affected sources in subpart UUUU would offer any additional flexibility in the ways described above.

VI. Building Blocks for Setting State Goals and Considerations

A. Introduction

Based on the states’ experiences and the EPA’s outreach with stakeholders as described above, the EPA has identified the measures underlying its BSER determination encompassing carbon intensity improvements and limitations on utilization that can meaningfully reduce CO₂ emissions from affected EGUs, with minimal adverse impacts on the reliability of the electricity
system, fuel prices, assets already improved with other control technology, and existing CO₂ reduction programs. We group these measures, which reflect current and projected practice and trends relevant to the industry, into four categories, which we consider “building blocks” for developing state emission performance goals. We provide an overview of these building blocks in subsection B. and more detailed discussion of each block in subsection C. In subsection D, we explain why as a legal matter these building blocks, taken together, constitute the “best system of emission reduction . . . adequately demonstrated” (BSER), which 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, we are mindful of numerous and varied stakeholder concerns. Many of these align with our approach to applying the building blocks, 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 CO₂ emissions.

Similarly, we recognize and appreciate that states have different circumstances. For example, states have differing access to specific fuel types and proportions of EGU types. 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 regional and multi-state reduction strategies. Some states already participate in a regional program that reduces CO₂ emissions, the RGGI, and we have noted the success of that program.

Another key consideration in application of these building blocks, 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 emissions reductions that longer-term actions, such as demand-side energy efficiency programs, may achieve.

B. Building Blocks for Setting State Goals

In the system of supplying energy, it is clear that a variety of approaches are available and being used to reduce CO₂
emissions. Emission controls for certain air pollutants depend on an add-on technological devices or technology. For CO₂, carbon capture and storage (CCS) technology is available but for reasons discussed below cannot at this time be looked to on a national basis for controlling emissions from currently operating EGUs. Accordingly, to reduce CO₂ emissions from existing EGUs, the EPA considered the other available approaches: (i) making emission rate improvements at affected EGUs (e.g., by improving heat rates, maximizing supply-side energy efficiency, or switching to lower-carbon fuels) and (ii) addressing emission levels at affected CO₂-emitting EGUs (e.g., by shifting dispatch from higher CO₂-emitting EGUs to lower CO₂-emitting EGUs or by reducing the overall demand for electricity).

The latter approach is based on the electric power sector’s unique nature – its large size, the diversity of fuel sources, and the fungibility of its product: electrons and electricity services. Limiting affected EGUs’ emissions reflects the recognition both that, at least to some degree in all states, electricity production is interchangeable among generation facilities – production at higher-emitting EGUs can be replaced by generation at lower-emitting facilities – and that reducing electricity demand generally will reduce CO₂ emissions from
affected EGUs. Not only is generation generally interchangeable, but the product—electrons—is as well. The agency recognizes that a combination of approaches that lower the carbon intensity of electricity production and reduce demand across generation facilities offers the most effective—and cost-effective—approach to achieving CO₂ emission reductions from affected EGUs.

From its extensive examination, the EPA has identified the following four main categories—“building blocks”—of measures undergirding the application of carbon intensity improvements and limiting CO₂ emissions at EGUs:

1. Lowering the carbon intensity of generation at individual affected EGUs (e.g., through heat rate improvements)

2. Reducing emissions of the most carbon-intensive affected EGUs to the extent that this can be accomplished cost-effectively by shifting generation to less carbon-intensive existing fossil fuel-fired EGUs, including NGCC units that are under construction

3. Reducing emissions of affected carbon-emitting EGUs to the extent that this can be accomplished cost-effectively by expanding the amount of new, lower (or no) carbon-intensity generation
4. Reducing emissions of affected carbon-emitting EGUs to the extent that this can be accomplished cost-effectively by increasing demand-side energy efficiency.

Each of the above four building blocks represents a demonstrated approach to addressing either carbon intensity improvements or the limitation of emissions at existing EGUs. In the next subsection, we discuss each of these building blocks at length.

C. Detailed Discussion of Building Blocks and Other Options Considered

In this section we discuss each of the building blocks in turn. For each building block we provide our proposed assessment of the technical potential and cost effectiveness of the building block within the context of the BSER determination, and we describe how we developed the data inputs used in the computations of state goals. We also discuss certain measures that we are not proposing to consider part of the best system of emission reduction. Additional detail is provided in the Greenhouse Gas Abatement Measures TSD.

1. Building block 1 - heat rate improvements

The first basic category of approaches to reducing CO₂ emissions from affected fossil fuel-fired EGUs consists of measures that reduce the carbon intensity of generation at
individual coal-fired steam EGUs 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 CO2 produced as a byproduct of fuel combustion. Heat rate improvements yield important benefits to affected sources by reducing their fuel costs.

a. Ability of heat rate improvements to reduce CO2 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

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63 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).

64 The EPA’s evaluation of potential CO2 reductions achievable through heat rate improvements focused on coal-fired steam EGUs because those are the units where heat rate improvements would have the greatest potential CO₂ reduction impact due to coal-fired steam EGUs’ greater carbon intensity.
electrical energy output (and useful thermal energy in the case of cogeneration units).\textsuperscript{65} The weighted-average annual heat rate of U.S. coal-fired EGUs is approximately \textbf{10,450 Btu per net kWh}. 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.\textsuperscript{66}

Several studies have examined the opportunities to employ heat rate improvements as a means of reducing CO\(_2\) emissions from coal-fired power plants. Among these, a 2009 study by the engineering firm Sargent & Lundy (S&L) used bottom-up engineering approaches evaluating potential heat rate improvements from specific equipment upgrades, including upgrades to boilers, steam turbines, and control systems. Based on this study, the EPA believes that implementation of all identified equipment upgrades at a facility could provide total

\textsuperscript{65} 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.

\textsuperscript{66} A small portion of some fossil fuel-fired EGU’s CO\(_2\) emissions may come from sources other than fuel, such as lime or limestone reagent used to capture sulfur dioxide (SO\(_2\)) in a scrubber. 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 tend to decrease when the amount of fuel used decreases.
heat rate improvements in a range of approximately 4 to 12 percent. (We recognize that individual EGUs would only be able to install the subset of the identified upgrades that were applicable to their specific designs or fuel types and that had not already been installed.)

In addition to the S&L study, which looked generically at the types of improvements that can be made at specific types of EGUs, historic heat rate data also provides a basis for 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) CO2 emissions and generation data, from which heat input and heat rate data can be computed. We have reviewed these data and have identified a number of 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, the analysis of individual EGU heat rate histories provides a strong basis for considering heat rate improvements 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.

For the best practices analysis, the EPA worked with the heat rate 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 MWh 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. 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. 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. 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 6.7 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 S&L study. In that study, S&L 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 are non-overlapping and that would generally be beyond the scope of investments we

Comment [A96]: Assuming variation in the data by state is minimal, EPA may want to make that clear to strengthen its case for using national numbers.
would expect to be made for purposes of achieving the best-practices heat rate improvements discussed above. Based on the average of S&L’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 already 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,
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 more than five percent of gross MWh generation. The analysis of 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

Comment [A08]: Any supporting literature/references we can add for parasitic load?

e.g. EPRI 2011 Technical Report – Program on Technology Innovation: Electricity Use in the Electric Sector (Opportunities to Enhance Electric Energy Efficiency in the Production and Delivery of Electricity). The report shows an average of 7.5% parasitic load (range of 4 to 12%) for coal generation, and a range of 1 to 10% parasitic load for NG-fired generation
opportunities for sources to improve their heat rates cost effectively.67

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. Because of the close relationship between an EGU’s fuel consumption and its CO₂ emissions, a six percent heat rate improvement would be associated with a reduction in CO₂ emissions of approximately six percent. We believe that this represents a reasonable estimate of the technical potential for CO₂ emission reductions that would be achievable from affected coal-fired 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 we have used an 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

67 As proposed, the state-specific goals are expressed in the form of CO₂ 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 CO₂ reductions would require additional procedures.
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 EGUs.

It should be noted that we have not evaluated the technical and economic potential for analogous heat rate improvements at types of EGUs other than coal-fired steam EGUs. We have therefore not identified such improvements as part of this building block.

c. Costs of heat rate improvements

By definition, any heat rate improvement made for the purpose of reducing CO₂ emissions will also reduce the amount of fuel the EGU consumes to produce its electricity output. The cost attributable to CO₂ emission reductions therefore would be at most 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, making heat rate
improvements a highly cost-effective approach for reducing CO₂ emissions from affected EGUs.

The EPA’s most detailed estimates of the average costs required to achieve the full range of heat rate improvements come from the 2009 S&L study discussed above. The S&L study 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 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 S&L 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, leaving

\[10,450 \text{ Btu/kWh} \times 8760 \text{ hours/year} \times 78\% \text{ utilization} \times \$2.62 \text{ per MMBtu} \times 6\% \text{ improvement} \times 0.000001 \text{ MMBtu/Btu} = $11.2 \text{ per kW-year.} \]

Data inputs for average coal-fired EGU heat rate, average coal-

\[68\]
approximately $3.10 per kW-year of carrying cost not recovered through fuel cost savings. At an average CO₂ emission rate of 0.976 metric tons per MWh, the same six percent heat rate improvement would reduce CO₂ emissions by 0.40 metric tons per kW-year.⁶⁹ Thus, the average cost of CO₂ reductions from heat rate improvements would be approximately $7.75 per metric ton of CO₂ ($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 CO₂ reductions would be $11.63 per metric ton.⁷⁰ 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 most cost-effective ones, the average cost of CO₂ reductions would fall to $5.81 per metric ton.⁷¹

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⁶⁹ 8760 hours/year * 78% utilization * 0.976 metric tons/Mwh * 6% improvement * 0.001 MW/kW = 0.40 metric tons of CO₂ per kW-year. The estimated average coal-fired EGU CO₂ emission rate per MWh is from the IPM 5.13 base case for 2020.

⁷⁰ $7.75 per metric ton of CO₂ * 6% / 4% = $11.63 per metric ton of CO₂.

⁷¹ $11.63 per metric ton of CO₂ * $50 / $100 = $5.81 per metric ton of CO₂.
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 CO₂ emission reductions from the heat rate improvements. Nevertheless, we still expect that, on average, the majority of the investment required to capture the technical potential for CO₂ emission reductions from heat rate improvements would be offset by fuel savings, making heat rate improvements a highly cost-effective approach to reducing CO₂ emissions from existing fossil-fueled EGUs.

Based on the analyses of technical potential and cost effectiveness summarized above, we propose to find that a six percent reduction in the CO₂ 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 cost-effectively implemented.⁷₂

⁷₂ We note that although we expect that heat rate improvements are also available from other fossil fuel-fired EGUs, because we

Comment [A101]: Is this consideration appropriate? Would it be stronger to say that for over half of the facilities, you expect the heat rate improvements to offset the fuel savings, and thus, it fits within the BSER criteria?
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 6.7 percent and 4 percent, respectively, particularly in light of the cost-effectiveness of heat rate improvements. We also solicit comment on approaches for estimating an additional amount of heat rate improvement due to efficiency-based reductions in parasitic load.

2. Building block 2 – dispatch changes among affected EGUs

The second basic category of approaches to reducing CO₂ emissions from affected fossil fuel-fired EGUs consists of measures that limit utilization, and therefore emissions, of high carbon-intensity affected EGUs – in particular, fossil fuel-fired steam EGUs – by replacing demand for generation at such facilities with generation at less carbon-intensive affected fossil fuel-fired EGUs – in particular, NGCC units that have less data from which to estimate those improvements we have conservatively not included CO₂ emission rate reductions for those EGUs in the state goals. However, states and sources would be free to use heat rate improvements at those other units to help reach the state goals.
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 CO₂ emissions

The nation’s EGUs are interconnected by transmission grids extending over large regions. These interconnections provide flexibility for EGU owners and grid operators, subject to various reliability and operational constraints, 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. Treating increments of generation as interchangeable, dispatch decisions are based on electricity demand at a given point in time, the variable costs of available generating resources, and system constraints. 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. With appropriate signals and incentives, owners and operators can consider EGUs’ CO₂ emission rates when selecting the order in which EGUs will be dispatched; indeed, operators of EGUs subject to existing market-based programs to limit emissions of pollutants such as SO₂ and NOₓ
have for many years factored directly into dispatch decisions
the costs associated with the EGUs’ emission rates of those
pollutants because each ton of emissions requires an emission
allowance that has an economic cost. Reducing or limiting
utilization, and therefore emissions, at high carbon-intensity
EGUs by replacing demand for generation at those EGUs with
generation at less carbon-intensive EGUs clearly has the
technical capability to reduce overall power sector CO₂
emissions.

b. Magnitude of re-dispatch

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 EGU are therefore generally the
units that operators use to respond to intra-day and intra-week
changes in demand (along with some hydroelectric units). 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 short-term — 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 CO₂ per MWh of electricity generated as a typical coal-fired EGU.

In order to estimate the potential magnitude of the cost-effective opportunity to reduce power sector CO₂ 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 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% for some groups.\textsuperscript{73}

We also researched historic 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 historic 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. These changes in generation patterns have been driven largely by changes over time in the relative prices of natural gas and coal.\textsuperscript{74} The relative fuel prices vary by location, as do the recent patterns of re-dispatch. However, in aggregate the historical data provide ample evidence indicating that, on average, existing NGCC units


\textsuperscript{74} Natural gas prices have fallen because of advances in production methods that have increased available supplies.
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 historic 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. 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. Thus, on a seasonal basis, a significant number of NGCC units achieved utilization rates between 50 and 80 percent, and 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 the entire season. 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 CO₂ emissions from existing high carbon-
intensity EGUs, would be technically feasible.

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 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).\textsuperscript{75} If the current pipeline and transmission systems allow these utilization rates to be achieved in peak hours, it is reasonable to expect that similar utilization rates should also be possible in other hours when constraints are typically less severe. The second reason supporting our view that gas and electric system 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 gas or electric 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 reason supporting a conclusion regarding the adequacy of infrastructure is that pipeline and transmission planners have repeatedly demonstrated the ability to methodically relieve bottlenecks and expand capacity.\textsuperscript{76} Further,


\textsuperscript{76} See, e.g., EIA, Natural Gas Pipeline Additions in 2011, Today in Energy; INGAA Foundation, Pipeline and Storage

Comment [A111]: Might want to strengthen/emphasize this section related to natural gas infrastructure adequacy in light of the recent cold weather (January/February 2014) that occurred and the concern among stakeholders of increased reliance on NG and potential reliability issues during cold weather due to NG availability issues, especially in the northeast e.g. could modify: "Thus, even if isolated gas or electric system constraints were to limit NGCC unit utilization rates in certain locations in certain hours, or during certain extreme weather events, this would not prevent an increase in NGCC generation overall across a state or broader region and across all hours." Also – with the changing gas supply landscape, might be better to reference a more recent report on natural gas pipeline additions (footnote 76).
we believe the flexible nature of the goals provides time for infrastructure improvements to occur should they prove necessary in some locations.

c. Cost of re-dispatch

The cost of the power sector CO₂ 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 analysis of the opportunity to reduce CO₂ emissions through re-dispatch. The

Comment [A112]: For purposes of establishing the BSER targets, did EPA conduct its modeling with transmission constraints included? If so, might be worth referencing that here too.
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 were used as the basis for assessing the costs and benefits of the overall proposal. Both sets of analyses were conducted using the Integrated Planning Model (IPM), 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.

The first set - the dispatch-only analyses - explored the magnitude and cost of potential opportunities to shift generation from existing coal-fired EGUs to NGCC units within defined areas. In the most restrictive scenarios, re-dispatch was simulated only between EGUs located in the same state. The purpose of analyzing these scenarios was to understand and demonstrate, even under a restrictive interpretation of the degree of re-dispatch that might constitute a component of the best system of emission reduction under CAA section 111(d), to

77 See Regulatory Impact Analysis for more detail.
what extent existing NGCC units could increase their dispatch
cost-effectively and without extreme 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. Specifically, the scenarios
required average NGCC unit utilization rates of 65, 70, and 75
percent. 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
constraints and requiring re-dispatch to occur exclusively
within a state’s existing fleet.

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 and a constraint prohibiting interstate re-

Comment [A115]: While the IPM constraint was
set to 65, 70, or 75% nationwide NGCC utilization,
what did IPM predict in it’s least cost solution, both
at a national and state level? What are the
differences in predictions between 65, 70, and 75%?
The way I think I understand IPM, the baseline/BAU
is projecting less NGCC utilization than these
utilization rates.

Comment [A116]: Based on our understanding
of the technical potential, we support EPA’s decision
to request comment on NGCC capacity factors of
75% and suggest that EPA also request comment on
levels exceeding 75%.

78 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.
dispatch opportunities, comparison to the business-as-usual case indicates that the average cost of the CO₂ reductions achieved ranged from [$xx] to [$xx] per metric ton of CO₂. We view these estimated costs as not unreasonable and therefore as supporting the use of a 70 percent utilization rate target for purposes of quantifying the cost-effective emission reductions achievable 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. This is because this scenario is based on the assumption that there will be no cost-effective re-dispatch opportunities among EGUs in different states, contrary to the reality that interstate flows of electricity routinely change in response to economic conditions. As a result, this case assumes no use of interstate electricity trading as a cost reduction mechanism. As discussed below, utilizing cost-effective interstate re-dispatch opportunities significantly reduces cost. It should also be noted that 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 CO₂ reduction measures that are part of the BSER, the state would seek to meet its emission reduction obligations using re-dispatch to the same extent as other states. In practice, under these circumstances, states would have flexibility to choose among alternative CO₂ reduction strategies that were part of the BSER, instead of employing re-dispatch to the maximum extent.

The EPA also analyzed dispatch-only scenarios where shifting of generation among EGUs was not limited by state boundaries. In one set of analyses, re-dispatch was simulated to occur across the multi-state regions overseen by independent system operators (ISOs) and other regional transmission organizations (RTOs), while in another set of analyses, national re-dispatch was simulated (subject to other constraints specified in the model, including transmission limits). In these scenarios with greater re-dispatch flexibility, the cost of achieving the quantity of CO₂ reductions corresponding to a nationwide average NGCC unit utilization of 70% was notably lower. We invite comment on whether the regional scenarios, which we believe reflect a more realistic representation of how re-dispatch would actually occur among EGUs located in multi-state regions, 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 their costs, than the cases in which the analysis of re-dispatch opportunities was limited according to state boundaries.

We also conclude from our analysis that the extent of re-dispatch estimated in this building block can be achieved without causing significant economic impacts. For example, in the 70 percent NGCC unit utilization rate scenario with restrictions on interstate re-dispatch, natural gas prices were projected to increase by a range of from [x] percent to [x] percent, which is well within the range of historic natural gas price variability. Projected wholesale electricity price increases ranged from [x] to [x] percent, which similarly is well within the range of historic electric price variability. 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 the economic impacts, including natural gas price impacts, described above for the most restrictive scenario to be considerably larger than would actually occur in real-world
compliance with this rule’s proposed goals. Operating on an interstate basis is expected to reduce costs and, as noted above, at least some states may have available less expensive reductions among the BSER measures. Consistent with this expectation, the comprehensive analyses used to assess the compliance costs and benefits of this proposal, which reflect the greater geographic extent of actual re-dispatch opportunities and a more complete representation of the additional flexibility available to states, show significantly smaller economic impacts. These analyses are discussed below in section X on the regulatory impacts analysis.

Based on the analyses summarized above, the EPA proposes that for purposes of establishing state goals, a reasonable estimate regarding the degree of re-dispatch that can be cost-effectively implemented is that electricity generation could be shifted from more carbon-intensive EGUs to less carbon-intensive EGUs within the state up to the point at which the state’s NGCC units would have annual utilization rates of 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 estimate of a 65 percent average utilization rate for NGCC units. In 2012, approximately 18 percent of existing NGCC units 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.

We also specifically invite comment on raising the NGCC utilization rate target to 75 percent.

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 – expanding the amount of new, less carbon-intensive generating capacity

The second basic category of approaches that create a basis for incorporating limiting emissions as an element of the BSER for CO₂ emissions from affected fossil fuel-fired EGUs consists of measures that reduce electricity demand at affected carbon-emitting EGUs by expanding the amount of lower-carbon generating capacity available to produce replacement generation. The opportunity discussed above to re-dispatch from higher-carbon to
lower-carbon EGUs within the affected fossil EGU fleet may be limited by the amount of underused less carbon-intensive capacity available to accommodate shifting of generation from more carbon-intensive EGUs. This limit can be relieved by adding new lower carbon-intensity generating capacity to the electric system or preserving existing low-carbon generating capacity, and measures that would do so constitute the third building block. Below we discuss several different types of generating capacity that could play this role: new renewable generating capacity, new and preserved nuclear capacity, and new NGCC capacity.

a. New renewable generating capacity

Renewable electricity (RE) generating technologies are a well-established part of the U.S. power sector. In 2012, five percent of total U.S. electricity generation was produced by renewable technologies, up from two 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.\(^79\) Production of this renewable generation displaces predominantly fossil fuel-fired generation and thereby avoids

\[^79\] Database of State Incentives for Renewables & Efficiency (DSIRE), http://www.dsireusa.org/summaries/index.cfm?ee=0&RE=0.
the CO₂ emissions from that displaced generation. EPA believes that renewable electricity generation is a proven and cost-effective way for states to reduce CO₂ emissions at affected EGUs.

To estimate the CO₂ emission reductions from affected EGUs achievable through increases in renewable generation, EPA has estimated a “best practices” scenario for renewable capacity development based on the RPS requirements already established by a majority of states. 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 regional contexts.80

80 EPA recognizes that individual RPS policies vary in their specification of where qualifying RE generation must occur. However, 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 cost-effective RE generation potential within the same region.
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 does not establish RPS requirements that any state must meet. 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 effectiveness.

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, EPA has grouped the states into six regions for purposes of developing the best practices scenario. 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

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81 Given their unique locations, Alaska and Hawaii are not grouped with other states into these regions. As a conservative approach to estimating cost-effective RE generation potential in Alaska and Hawaii, EPA has developed RE generation targets for each of those states based on the lowest values for the six regions evaluated here.
scenario’s targets. The grouping of states into these six regions is shown in Table 3 below.

Table 3: Regions for Development of Best Practices RPS

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

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

Comment [A130]: It would be helpful to include an indicator, e.g., *, for states that have RPSes – it will be easier to determine what the average for each region is based on. A different notation could be used for the DC and VT footnotes.

Comment [A131]: Consideration/applicability of Capitol Power plant in DC? The plant secured permits last year to transform into an NG cogeneration plant.
The best practices scenario for each state consists of growing annual levels of RE generation\(^8\) estimated based on application of an annual RE growth factor to the state’s historic 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. 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.

Next, 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, EPA averaged the existing RPS percentage requirements that will be applicable in 2020 and multiplied that average percentage by the total 2012

\(^8\) The bulk of hydropower is excluded from this approach to quantify BSER-related RE generation potential because state RPS requirements typically exclude the historical output from pre-existing hydropower projects from qualifying.
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, this amount is less than its RPS target 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, 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, we used the annual amounts for the years 2020 through 2029. For computation of the alternate state goals on which we are seeking comment, we used the annual amounts for

83 See Section VIII below for further discussion of timing requirements for state plan submittals.
the years 2020 through 2024. The cumulative RE amounts for each state, represented as percentages of total generation, are shown in Table 4.

Table 4: State RE Generation Levels for State Goal Development (Percentage of Annual Generation) 84

<table>
<thead>
<tr>
<th>State</th>
<th>2012 Proposed Goals</th>
<th></th>
<th>Alternate Goals</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Interim Level</td>
<td>Final Level</td>
<td>Interim Level</td>
<td>Final Level</td>
</tr>
<tr>
<td>Alaska</td>
<td>1%</td>
<td>5%</td>
<td>10%</td>
<td>2%</td>
</tr>
<tr>
<td>Alabama</td>
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<td>6%</td>
<td>9%</td>
<td>4%</td>
</tr>
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<td>Arkansas</td>
<td>3%</td>
<td>5%</td>
<td>7%</td>
<td>4%</td>
</tr>
<tr>
<td>Arizona</td>
<td>2%</td>
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84 Vermont and the District of Columbia are excluded from this table because we are not proposing goals for those jurisdictions.
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We note that the RE generation levels represent total amounts of RE generation, rather than incremental amounts. 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 to deploy 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 that have already achieved a higher proportion of their generation from renewable resources are assumed to have less additional renewable generation to deploy as part of the BSER framework informing state goals, in comparison to states in that region that have not achieved as high a share of RE generation to date. 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.

Several studies have found projected the cost 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" found the median change in retail electricity price projected to be $0.0004 per kilowatt-hour (only a 0.7 percent increase), the median monthly bill impact to be between $0.13 and $0.82, and the median CO₂ reduction cost to be $3 per metric ton.85

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.86

While RPS requirements will continue to grow over time, EPA does not expect this anticipated expansion to fall outside the historical norms of deployment. 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 2007-2012 has exceeded 6 GW per year.87 In addition, recent improvements in RPS compliance rates indicate to 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.88

88 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
We invite comment on this approach to treatment of new renewable capacity as an emission limitation component of the best system of emission reduction and a basis for part of the quantification of state goals. We also request additional costs and electricity price information.

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 for reducing CO$_2$ emissions from affected fossil fuel-fired EGUs.

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 compliance. This estimate does not represent official compliance statistics, which vary in methodology by state.
generating capacity additions have consisted of NGCC or renewable capacity. Nevertheless, five new 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 CO₂ emission reductions available from completion of these units as zero for purposes of setting states’ CO₂ reduction goals. Completion of these units therefore represents a highly cost-effective opportunity to reduce CO₂ emissions from affected fossil fuel-fired EGUs. For this reason, we are proposing that the emission reductions achievable at affected sources due to the generation provided at the identified new nuclear units should be factored into the state goals for the respective states where these new units are located.

Another way to increase the amount of available nuclear capacity is to preserve existing nuclear EGUs that would 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, Crystal River 3, Kewaunee, Vermont Yankee, and Oyster Creek. While each retirement decision is based on the unique circumstances of that
individual unit, EPA believes that increased fixed costs associated with unit age play a role, particularly as the units approach the point of deciding whether to apply for renewal of their initial operating licenses (which have 40-year terms). Of the existing fleet of nuclear EGUs, units with 7.8 GW of capacity, representing approximately eight percent of total existing U.S. nuclear generating capacity, have not yet submitted applications for license renewal to the Nuclear Regulatory Commission. Without making any judgment about the likelihood that any individual EGU will retire, we view this eight percent share of nuclear capacity as a reasonable proxy for the amount of nuclear capacity at risk of retirement for reasons including, but not limited to, additional fixed costs related to age and relicensing.

We believe that, based on available information regarding the cost and performance of the nuclear fleet, preserving the operation of this existing, at-risk nuclear capacity is likely to be a relatively cost-effective approach to achieving CO2 reductions from affected EGUs. Retaining the estimated eight percent of at-risk nuclear capacity could avoid 175 to 250 million metric tons of CO₂.89 According to a recent report, 89 Assuming replacement power for at-risk nuclear capacity is sourced from new NGCC capacity at 800 lbs/MWh or the power

Comment [A144]: Does this include plants such as San Onofre in the not yet submitted license renewal?

Comment [A145]: Please consider providing more information on the choice of 8%, may be vulnerable to critique.

Comment [A146]: Please clarify whether this is an annual or cumulative estimate.

Comment [A147]: Seems too high.

89% of the nuclear capacity is 61M/MWh (800*61M)/2205=22M metric tons (1127*61M)/2205=32M metric tons

My calculation must be off by a factor of 8 somehow.
nuclear units may be experiencing up to a $6/MWh shortfall in covering their operating costs with electricity sales. Assuming that such a revenue shortfall is representative of the incentive to retire the estimated eight percent of at-risk nuclear capacity, one can estimate the value of offsetting the revenue loss at these at-risk nuclear units to be about $12 to $17 per metric ton. EPA views this cost as reasonable. We therefore propose that the emission reductions achievable by retaining in operation eight percent of each state’s existing nuclear capacity should be factored into the state goals for the respective states.

For purposes of goal computation, generation from new 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.

Comment [A148]: How is this calculated?
I would think it would be $370M (operating loss)/175M-250M Metric Tons= $1.5-$2. But if my calculation of 22M-32M avoided metric tons is correct then $12-$17 per metric ton seems right.

Comment [A149]: To offer the critique the prior comment makes, why should the “vulnerable” 8% be applied to individual states?
We invite comment on all aspects of the approach discussed above. In addition, we specifically request comment on the following questions: Should we estimate an 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 EPA or another government agency, or commercial projections? What specific data sources should we consider for those permits or projections?

c. New NGCC capacity

In subsection 2 above, we discussed the opportunity to limit CO₂ emissions by replacing generation at high carbon-intensity affected EGUs with generation from lower-carbon generation from existing NGCC units.91 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.

91 For purposes of this proposal, NGCC units that have commenced construction as of January 8, 2014 are “existing” units.
equally to new NGCC units. \(^92\) 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.

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 could be somewhat more costly. 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. 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 might also be attributable.

\(^92\) 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 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.
to the CO2 reduction opportunity, increasing to some uncertain extent the cost of the CO2 reductions at affected EGUs achieved through re-dispatch to those new NGCC units.

It is also worth noting that, unlike generation from other types of potential new generating capacity such as wind, solar, and nuclear capacity, NGCC generation does produce CO2 emissions. Because of this distinction it is less apparent that addition of new NGCC capacity, as opposed to those other types of capacity, should be a primary building block of a strategy for reducing CO2 emissions from the power sector.

We therefore do not propose any “best practices” quantities of new NGCC capacity to include in state goals at this time. However, we invite comment on whether new NGCC capacity should be reflected as an emission limitation component of the best system of emission reduction, recognizing the potential effectiveness of adding and operating new NGCC capacity as a means of reducing CO2 emissions from affected EGUs. Further, if we were to reflect quantities for new NGCC capacity in the state goals, how should we determine those quantities – for example, according to the issuance of permits, a conservative percentage of historic state additions of NGCC capacity, projections of new NGCC construction by EPA or another government agency, or commercial projections?

Comment [A151]: Any considerations for the role of new flexible and efficient NGCCs in helping integrate the variability of renewables onto the grid and reducing overall CO2 emissions (fast generation that is capable of cycling/operating at partial load while maintaining efficiency)?

Comment [A152]: This would be a bad idea. Why, because including new NGCC into the state goal would make a statement that the 2030 goals are the rate goals for the entire IGU sector, not just the existing sources as of 2014 and conveyed forward. This would send a bad message internationally (i.e., some of the rates for predominantly coal states are in the 1600 – 1800 lb/MWhr region, and conversely other states are so low (325 lb/MWhr) that they would not be able to build even an NSPS compliant NGCC in out years. Suggest a) making very clear that the current proposal relates only to the existing EGU fleet and b) note the adverse messaging difficulties if we were to start including genuinely new fossil IGU sources into goal setting.

Comment [A153]: It very much should be part of the state goals. NGCC presents great opportunities as a transition system to renewables. Also including NGCC in the goal setting will encourage NGCC with CCS. EPA should include NGCC in the state goals and if it wants take comment on not including it.
4. Building block 4 – demand-side energy efficiency

The third basic category of approaches that create a basis for incorporating limiting utilization, and therefore limiting emissions, as an element of the BSER for CO₂ emissions from affected fossil fuel-fired EGUs consists of measures that reduce the demand for generation at those sources by reducing the overall quantity of generation demanded by end-users.

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 method of reducing CO₂ emissions at those EGUs. More than 40 states have 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.93 Additionally, multiple studies have found that significant improvements in end-use energy efficiency can be

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realized at less cost than the savings from avoided power generation.94

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 displaced when demand is reduced. Consequently, reductions in fossil fuel-fired utilization may be achieved cost-effectively by reducing electricity consumption and, by the same token, reductions in electricity consumption generally cause reductions in the amount of fossil fuel-fired generation, thereby avoiding the CO₂ emissions associated with the avoided generation. In this manner, in 2011, state demand-side energy efficiency programs are estimated to have reduced CO₂ emissions by 75 million metric tons.95 And when integrated into a comprehensive approach for

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95 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
addressing CO\textsubscript{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 further reduce carbon intensity. This potential effect reinforces the appropriateness of incorporating demand-side efficiency improvements in a comprehensive approach to address power sector CO\textsubscript{2} emissions.

b. “Best practices” for demand-side energy efficiency

To estimate the potential CO\textsubscript{2} reductions at affected EGUs that could be achieved through 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 cost-effective demand-side energy efficiency technologies and practices. 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 is

http://www.edisonfoundation.net/iei/ourwork/Pages/issuebriefs.aspx.
intended to represent 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 demonstrated 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,\textsuperscript{96} building energy codes, state appliance programs,\textsuperscript{96} and numerous strategies are employed, including targeted rebates for high-efficiency appliances;

\textsuperscript{96} 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;
standards (for appliances without federal standards), tax credits, and benchmarking requirements for building energy use. Energy efficiency programs are activities 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 (EERS) to drive investment in energy efficiency programs; some have relied on other strategies. According to data and analyses from sources including EIA and the American Council for an Energy Efficient Economy (ACEEE), as well as the EPA’s own analysis, 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. These savings levels are energy audits with recommendations for cost-effective, energy-saving upgrades; and processes to certify energy efficiency service providers.

97 See the Existing State Actions TSD for descriptions of the full array of demand-side energy efficiency policies currently employed by states.

98 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.

99 See the Greenhouse Gas Abatement Measures TSD for more information.
realized exclusively through the adoption and implementation of energy efficiency programs. The energy savings and cost data underpinning these analyses are derived from energy efficiency program reports required by state public utility commissions. 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.100

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 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 cost-effectively by all states given adequate time.

100 See the EM&V section of the state Plan TSD for more information on EE program evaluation.
For states with more limited EE program experience, 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\(^{101}\) 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 a state already close to a 1.5 percent annual savings rate can expand its energy efficiency programs to reach that rate more quickly than 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.\(^{102}\)

For states already at or above the 1.5 percent annual incremental savings rate, we estimate that they would sustain a 1.5 percent rate through 2030. 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. The

\(^{101}\) 2012 is the most recent year for energy efficiency program incremental savings data reported using EIA Form 861.

\(^{102}\) See the Greenhouse Gas Abatement Measures TSD for more information.
savings from energy efficiency programs are cumulative, meaning that, in simplified terms, a state implementing a sustained program 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. To determine the avoided MWh quantities of generation that are used in the procedure for computing the state goals described above, the cumulative percentages for each state are multiplied by the state’s 2012 historical electricity sales reflected in EIA’s detailed state data.103

As indicated above, the EPA is also taking comment on a less stringent alternative for goal-setting. Under this approach, the demand-side energy efficiency requirement is...

103 EIA, Retail Sales of Electricity by State by Sector by Provider, Nov. 12, 2013, available at http://www.eia.gov/electricity/data/state/. The data are adjusted to reflect transmission and distribution losses.
relaxed by using 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 historic 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. 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.

c. Costs of demand-side energy efficiency

The EPA expects implementation of demand-side energy efficiency programs as reflected in the best practices scenario to be a highly cost-effective approach to reducing greenhouse

104 See the Greenhouse Gas Abatement Measures TSD for more information.
gas emissions from the existing fossil fuel-fired EGUs. The processes by which states develop funding for these 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 their cost-effectiveness even before the additional benefit of CO₂ reductions is considered.¹⁰⁵ Federal and independent studies project 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.¹⁰⁶ In our view, the factors mentioned above indicate that the cost of CO₂ reductions achieved through implementation

¹⁰⁵ Some states do include a valuation of CO₂ benefits as part of their evaluations of cost effectiveness.
of demand-side energy efficiency at the levels reflected in the best practices scenario is likely to be very low and may even be less than $0 per metric ton.\footnote{As described below and in the Goal Computation TSB, 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 CO₂ emission reductions achievable through demand-side energy efficiency programs, implementation of such programs is likely to be a highly cost effective approach to reducing CO₂ emissions even for a state whose own affected EGUs achieve only part of the CO₂ emission reduction benefit from the state’s demand-side energy efficiency efforts.}

Another approach to evaluating the cost effectiveness of demand-side efficiency is to compare its cost to avoided power system costs. The costs associated with the best practices scenario were estimated based upon a synthesis of historical studies of energy efficiency program costs. Specifically, cost estimates were developed by applying a uniform levelized average cost per kWh of saved energy across the life of the energy efficiency investments. The cost per kWh 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. Because we did not attempt to estimate the energy savings that could be achieved through state-implemented energy efficiency programs, 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 CO₂ emission reductions achievable through demand-side energy efficiency programs, implementation of such programs is likely to be a highly cost effective approach to reducing CO₂ emissions even for a state whose own affected EGUs achieve only part of the CO₂ emission reduction benefit from the state’s demand-side energy efficiency efforts.
policies incremental to energy efficiency programs, such as building energy codes or state appliance standards, we did not consider those policies in our cost estimates.

The estimated cost per kWh was selected based on several previous reviews of studies of energy efficiency program costs using engineering-based, bottom-up estimates of the average cost of saved energy under various programs.\textsuperscript{108} For example, an EPA review conducted in 2009 found a range of annualized costs between $12 and $52 per MWh of electricity saved,\textsuperscript{109} while a more recent review from the American Council for an Energy-Efficient Economy derived a cost of $51 per MWh of electricity saved.\textsuperscript{110}

We have evaluated cost effectiveness of the best-practices demand-side energy efficiency scenario using a cost range of $71 to $88 average cost per MWh of electricity saved. This is a conservatively high estimate based on the literature, incorporating cost escalation over time to account for possible

\textsuperscript{108} All states that implement ratepayer-funded energy efficiency programs (more than 40) employ engineering-based, bottom-up estimation methods as their primary basis for analyzing the associated costs and benefits.
effects of the substantial level of national demand reductions reflected in the best-practices scenario. Even at this conservatively high cost, the EPA believes that the best-practices demand-side energy efficiency scenario would represent a cost-effective approach to reducing GHG emissions from affected fossil fuel-fired EGUs. This cost is comparable to the estimated levelized cost of building and operating a new NGCC unit, at $64 to $83 per MWh (as estimated by the EPA using data inputs similar to those of the IPM 5.13 base case, dependent on gas price), even before the benefit of lower CO₂ emissions is considered.

Recognizing this history of demonstrated successful state implementation of demand-side energy efficiency programs, the EPA proposes to find that for purposes of establishing state goals, a reasonable estimate of the demand-side energy efficiency that can be cost-effectively achieved is the amount resulting from implementation of a comprehensive set of demand-side energy efficiency programs at a level consistent with the best practices scenario discussed above.

Further details regarding the data and methodology used to evaluate the potential for demand-side energy efficiency programs to cost-effectively reduce power sector CO₂ emissions 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 inclusion in the best system of emission reduction and the level reflected in the less stringent scenario. We also specifically invite comment on increasing the annual incremental savings rate to 2.0 percent to reflect an estimate of the additional electricity savings achievable from state policies not reflected in the 1.5 percent rate, such as building energy codes and state appliance standards.

5. Potential emission reduction measures not used to set proposed goals

There are two additional potential measures for reducing GHG emissions from EGUs that the EPA does not propose to consider part of the best system of emission reduction 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, and carbon capture and storage (CCS).

a. Fuel switching at individual units

One technically feasible approach for reducing CO₂ 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 CO₂ 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 CO₂ 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 CO₂ 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 CO₂ 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 CO₂ reductions achieved through gas conversion or co-firing ranges from $67 per metric ton to $109 per metric ton. The low end of the range of CO₂ 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 CO₂ reduced.

The EPA’s economic analysis suggests that there are more cost effective opportunities for coal-fired utility boilers to reduce their CO₂ 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 CO₂ emissions that may make natural gas co-firing economic in some circumstances. One example is that natural gas reburn strategies that involve co-firing with 10 to 20 percent natural gas can be an effective control strategy for NOx emissions and, thus, can offset operational (and in some cases, capital) costs associated with other NOx controls such as SCR or 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 economic than either installing non-CO₂ emission controls or taking other measures, such as transmission upgrades, that could be associated with retiring the unit. Finally, beyond the reasons just described 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 CO₂ emissions from existing fossil fuel-fired EGUs is through the application of carbon capture and storage\footnote{This is also sometimes referred to as “carbon capture and sequestration.”} 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

\footnote{This is also sometimes referred to as “carbon capture and sequestration.”}
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 noted that identifying CCS as BSER for new natural gas-fired stationary combustion turbines would likely result in higher nationwide electricity prices and could adversely affect the supply of electricity, because the majority of new fossil-fuel-fired generating capacity is projected to consist of NGCC units.

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 commercial-scale as a retrofit at SaskPower’s Boundary Dam plant in Canada. However, the costs of integrating

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**Comment [A180]**: IMPORTANT: This language is incorrect regarding NG-CCS and the basis for the proposed NSPS decision, and should be substituted with agreed text from the NSPS proposal that is based on the concept of “not adequately demonstrated” at this time.

**Comment [A181]**: Then why is it not included in bin 3?

**Comment [A182]**: Given recent news, does EPA still think it’s prudent to say “expected soon”? How soon is soon?
a retrofit CCS system into an existing facility would be expected to 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 CO₂ emissions from existing fossil fuel-fired EGUs. The EPA does solicit comment on all aspects of applying CCS to existing fossil fuel-fired EGUs, but does not expect to finalize CCS as a component of 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. We invite comment on this proposed finding.

D. Determination of the Best System of Emission Reduction

1. Overview

The EPA is proposing that the measures in the 4 building blocks, taken together, constitute the “best system of emission reduction ... adequately demonstrated” (BSER) for the standards of performance that the section 111(d) state plans must apply to affected EGUs. There are two alternative, but complementary, approaches to explaining how the building blocks provide the basis of the proposed determination of BSER.

Both approaches are based on the fact that the measures described in the four building blocks meet the criteria specified in the statute and are currently used by owners of EGUs across the country to reduce CO2 emissions.

The first approach is that the building blocks encompass two sets of measures that the affected EGUs may apply to their own operations to reduce their emissions: (i) undertaking equipment and process changes that improve efficiency (building block 1 -- heat rate improvements), and (ii) reducing utilization to the extent of the availability of lower-emitting fossil-generation, zero-emitting generation, and demand
reduction by means of end use energy efficiency measures (building blocks 2, 3, and 4, respectively). The second approach treats building block 1 the same as under the first approach, but treats building blocks 2, 3, and 4 as parts of the integrated electricity system that have the effect of reducing utilization at the affected EGUs.

2. Statutory and regulatory provisions as well as EPA interpretation

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. 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 emissions reductions that the system would generate.
- The costs of the system must be reasonable. The EPA may consider the costs on the source level, the industry-wide level, and, at least in the case of the power sector, on the national level in terms of the overall costs of electricity and the impact on the national economy over time.
- The EPA must also consider that CAA section 111 is designed

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113 As discussed in the January 2014 Proposal, the D.C. Circuit’s case law formulates the cost consideration in various ways: the costs must not be “exorbitant[ ]”, Essex Chemical Corp. v. Ruckelshaus, 486 F.2d 427, 433 (D.C. Cir. 1973), see Lignite Energy Council v. EPA, 198 F.3d 930, 933 (D.C. Cir. 1999); “greater than the industry could bear and survive,” Portland Cement Ass’n v. EPA, 513 F.2d 506, 508 (D.C. Cir. 1975); or “excessive” or “unreasonable.” Sierra Club v. Costle, 657 F.2d 298, 343 (D.C. Cir. 1981). In the January 2014 Proposal, EPA stated that these various formulations of the cost standard ... are synonymous,” and, for convenience, EPA used “reasonableness” as the formulation. EPA takes the same approach in this rulemaking.
to promote the development and implementation of technology.

Other considerations are also important, including that the EPA must also consider energy impacts, and, as with costs, may consider them on the source level and on the nationwide structure of the power sector over time. Importantly, the EPA has discretion to weigh these various considerations, may determine that some merit greater weight than others, and may vary the weighting depending on the source category.

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

In the framework regulations, the EPA interpreted CAA section 111(d) as giving the agency the authority to determine the required stringency of the standards of performance established for affected existing sources and, as noted, we are not re-opening that interpretation in this rulemaking. Under the framework regulations, each guideline document is to contain an emission guideline that reflects the application of the BSER to affected sources. 40 CFR 60.22(b)(5).

3. Heat rate improvement and reduction in utilization approach
The first approach EPA is proposing as the basis for determining that the 4 building blocks constitute the “best system of emission reduction ... adequately demonstrated” is that they consist of two sets of measures that the affected EGUs may apply to their own operations to reduce their emissions - equipment and process changes that improve heat rate, and reduction of utilization - and each of those sets of measures meets the criteria to qualify as a component of the BSER.

The measures in building block 1 (heat rate improvements) entail improvements in the efficiency of the affected EGU’s equipment or processes. The measures in the building block 2 entail reductions in generation by the fossil-fired steam-generating EGUs, with the amount of reduced generation corresponding to the amount of increased generation available at natural gas combined cycle units. The measures in building blocks 3 and 4 entail reductions in generation by the fossil-fired EGUs, with the amount of reduced generation corresponding to the amount of new low- or zero-carbon generation and increased demand-side energy efficiency that is available.

Each of these sets of measures is technically feasible. As the above discussion of the building blocks indicates, the measures that result in heat rate improvements are well-established. Reducing generation of higher emitting units either

Comment [A188]: How does BB 3-4 fit in? because a facility can “reduce utilization”? Also, how does BB 2 fit this definition for NGCC units, if they increase their use?

Comment [A189]: So NGCC units are not considered “affected units” given this explanation?
by shifting generation to lower, or zero emitting units or by using demand side strategies that provide the same underlying services with less electricity is also technically feasible and widely used, as discussed below.

In addition, as noted in the above discussion of the building blocks, each of the sets of measures results ineffective in reducing emissions. Moreover, their costs and energy impacts are not unreasonable when viewed either on the individual source level or through the lens of the electricity system as a whole. As noted, states and regulated entities will have flexibility when developing compliance strategies to emphasize whichever measures best suit their particular circumstances, and that flexibility will further improve cost-effectiveness. The analysis the EPA has 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 XI of the regulatory impacts analysis, the results indicate that the proposed goals are readily achievable with no adverse impacts on power 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. Moreover, the costs tend to decline over time as states and regulated entities take advantage of the available flexibility and deploy more cost-effective measures (notably demand-side energy efficiency). The EPA considers this analysis strong confirmation of the cost effectiveness of the building blocks in combination as the best system of emission reduction.

In addition, the improvements in heat rate through the building block 1 measures and the limitations on utilization in association with the measures in building blocks 2, 3, and 4 provide a broad range of options for compliance which encourages the innovation or development of technology or other practices that reduce emissions.

With respect to the remaining BSER criteria, the EPA believes that the measures in the building blocks would not cause adverse non-air health and environmental impacts or increase energy requirements; indeed, the most likely such impacts would be co-benefits. Heat rate improvements cause fuel resources to be used more efficiently, reducing adverse impacts associated with fuel extraction and disposal of combustion waste products. Addressing emissions levels at affected EGUS through reduced utilization associated with re-dispatch to less carbon-
intensive units, replacement by low- or zero-carbon emitting generation, or demand-side energy efficiency would generally result in lower emissions of other pollutants because less carbon-intensive EGUs also tend to have lower emissions of other pollutants and because less overall fossil-fired generation reduces emissions of other pollutants.

It should also be emphasized that the measures in each building block are consistent with actions currently being taken in the power sector as well as with future trends, which confirms our view that they comprise the BSER.

4. Components of electricity system

The second approach EPA is proposing as the basis for determining that the 4 building blocks constitute the “best system of emission reduction ... adequately demonstrated” is that they consist of four sets of measures that result in reduced CO₂ emissions from the affected sources. The measures in building block 1 are a component of BSER because, to reiterate, they reduce emissions by improving affected-source efficiency. Each of the measures in the other building blocks (blocks 2, 3 and 4) are components of the BSER because of the nature of the electricity system. As discussed above, the electricity system is an integrated system through which fungible products—electricity and electricity services—are produced and

Comment [A192]: How do conventional pollutant emissions rates compare between coal and gas units, post MATS?
delivered by a diverse group of EGUs operating within networks connecting them to each other and to their product purchases and users. This electricity system allows generation by the affected sources, and therefore emissions from those sources, to be reduced in association with increasing generation at less carbon-intensive EGUs and expanding the amount of low- or zero-carbon generating capacity connected to the electric grid, as well as by reducing the demand for electricity. As discussed above, this integrated nature of the electricity system has long been central to efforts to reduce costs in general, assure reliability, and implement pre-existing pollution control requirements in the least cost manner. As also noted above, some states, including the members of RGGI, are already relying on the integrated nature of the electricity system to reduce CO₂ emissions from EGUs.

In particular, under this approach, increased generation from NGCC units, in accordance with building block 2, is viewed as a component of a system that reduces generation at fossil-fired steam generating units, and thereby reduces overall CO₂ emissions from fossil-fired EGUs. Similarly, under this approach, increased low- or zero-carbon generation, in accordance with building block 3, and decreased demand, in accordance with building block 4, are each viewed as other
components of the same system that reduce generation at fossil-fired EGUs, and thereby reduce CO₂ emissions from those EGUs.

Viewed in this manner, all of the measures in the building blocks qualify as components of the BSER. Each of the building blocks’ sets of measures is technically feasible and is already being widely implemented. The heat rate improvements (building block 1) are technically feasible, for the reasons discussed in the earlier part of this section. The re-dispatch (building block 2), increased low- and zero-carbon intensity generation (building block 3), and demand-side energy efficiency (building block 4) are technically feasible for the reasons described in the above discussion of those building blocks. The evaluation of the rest of the factors concerning BSER are the same as discussed in the earlier part of this section. It bears reiterating that the EPA’s proposed conclusions that these measures qualify as BSER are confirmed by both the extensive practice within the electricity sector of relying on the same measures to reduce costs and implement pollution control requirements, while maintaining reliability, and the current practice of some states of relying on the same measures to reduce EGU emissions of CO₂.

It should be noted that all of the measures in the building blocks that are needed to achieve the requisite emissions
reductions may be undertaken by the affected EGUs. That is, the affected EGUs may undertake the equipment and process changes that result in heat rate improvements, as described in building block 1. The affected fossil-fired steam-generating EGUs may reduce generation, and the affected NGCC units may increase generation, to achieve the re-dispatch described in building block 2. The affected EGUs may invest in the new low- or zero-carbon intensive generation described in building block 3, and the affected EGUs may also invest in many of the demand-side energy efficiency measures described in building block 4. (These measures are described as the “utility portfolio” measures elsewhere in this preamble). The fact that the affected sources may themselves implement or invest in measures that reduce their emissions supports treating those measures as components of the BSER.

In fact, there are many cases in which companies have reduced emissions through shifting generation away from higher emitting units to lower or zero emitting units, or through reducing overall electric demand through DSM). In some cases this has occurred in response to goals set at the company level, in others at the state level and in others at the regional level. Companies’ choices and policies implemented by states may impact decisions about dispatching of lower instead of higher...
emitting generating units both as part of the short term dispatch process and as part of longer term business planning processes. We believe that the flexibilities the proposed emission guidelines provide a variety of mechanisms and temporal flexibility will allow states to implement a variety of mechanisms that can reduce emissions both as part of those shorter term dispatch decisions and as part of longer term business planning processes.

At the company level, a number of utilities have developed climate mitigation plans that are designed to significantly reduce emissions of CO\textsubscript{2}. In many of these plans, companies set a single company-wide emission target then use combinations of strategies such as fuel switching, increased energy efficiency, increased renewable generation and/or increased nuclear generation to achieve those goals. Changes from these types of plans occur over time as companies make decisions about generation mix and demand side strategies that change the way they dispatch.

California and Colorado provide two examples of how a statewide (or company-wide within a state) target set with consideration of the wide range of mitigation options and designed to provide flexibility to meet those options can be implemented. California enacted its Global Warming Solutions Act
in 2006 (i.e. AB32), requiring the state to reduce its GHG emissions to 1990 levels by 2020 and 80 percent below 1990 levels by 2050. According to California, “the integrated nature of the 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.” As a result, California takes a comprehensive approach (or relies upon a suite of mechanisms) to reduce emissions in the state, using energy efficiency programs, renewable energy programs as well as procurement processes and an economy-wide cap and trade program, along with other programs.

The Colorado Clean Air Clean Jobs Act (CACJA), signed into law on April 19, 2010, required investor-owned utilities (IOUs) with coal plants to submit a multi-pollutant plan to the state to meet current and foreseeable EPA standards for NOx, SO2,

115 December 27, 2013 Letter from Mary D. Nichols, Chairman of California Air Resources Board, to EPA Administrator Gina McCarthy.
particulates, mercury, and CO₂. Rather than prescribing specific control technologies, the law allowed for flexibility for the utilities to select the best set of measures to achieve the emission reductions, including by retiring, retrofitting or repowering plants and replacing retired plants with natural gas and other low- or non-emitting energy plants and through end-use efficiency measures.¹¹⁷

The California plan has put in place mechanisms that affect both companies’ longer term planning decisions and their short term dispatch decisions. Understanding the market dynamics that will occur because of the need to hold emissions allowances coupled with reduced demand from demand side programs impacts longer term decisions companies make about investment in both existing and new plants. The price of allowances also impacts hourly dispatch decisions and sends companies a market signal to which they take action in response to reduce use of higher emitting generators and increase use of lower emitting generators.

The Colorado Plan, which set explicit requirements for development of new renewable generation as well as requirements

to phase out older coal units, generally focused more on impacting companies’ longer term planning decisions.

Mechanisms have also been put in place regionally that have these same impacts. For example, nine northeast and mid-Atlantic states participate in the Regional Greenhouse Gas Initiative (RGGI), a market-based emissions budget trading program that sets an aggregate limit on CO₂ from fossil fuel fired power plants in the participating states. To comply with the program, each source must acquire allowances, through purchases or by allocation from the state, equal to their emissions, and must surrender them at the end of each compliance period. The RGGI program provides flexibility to regulated sources using a variety of mechanisms. The RGGI program allows for trading among regulated and non-regulated parties, creating a market for emission allowances. It provides additional flexibility through multi-year compliance periods, allowance banking, offsets, an auction reserve price and cost containment reserve of allowances. Operating in this regime, EGUs take a variety of actions including those that affect their utilization levels that in turn affect their emissions levels.

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118 Participating states include Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont; RGGI website: [http://www.rggi.org/rggi](http://www.rggi.org/rggi)
Because, under CAA section 111(d), the standards of performance that are based on the BSER are established by the states in state plans, measures that the states are authorized to enact under state law may be considered to be part of the BSER. Therefore, for example, the demand-side energy efficiency measures that are described as the “state portfolio” measures elsewhere in this preamble may also be considered part of the BSER.

5. Combined categories

As discussed above, the EPA is co-proposing combining the category of steam-generating 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 CO₂ emissions. The EPA solicits comment on whether combining the categories is, as a legal matter, a prerequisite for identifying as a component of the BSER re-dispatch between sources in the two categories (i.e., re-dispatch between steam-generating EGUs and NGCC units), or facilitating averaging or trading systems that include sources in both categories, which states may wish to adopt.

6. Severability

We consider our proposed findings of 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 BSER consists of the remaining building blocks.

7. Solicitation of comment

We invite comment on all aspects of our proposed interpretation of the BSER for CO₂ emissions from existing fossil fuel-fired EGUs, both as identified above and as further discussed in the Legal Issues Memorandum, although, as noted, we are not soliciting comment on issues that were resolved by the framework regulations and therefore are not being re-opened here. In particular, we invite comment on whether any of the types of measures discussed above, and any other potential measures recommended by commenters, must, may, or may not be considered as the basis for the BSER for legal, technical, or economic reasons. With regards to comments received during the stakeholder comments, some commenters noted that trading programs like RGGI have been successful at reducing GHGs, other commenters solicited 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 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 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 CO₂ 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 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 four building blocks, in this case by 2025, with interim goals that would apply over a 2020-2024 phase-in period.

The proposed goals are expressed in the form of state-specific, adjusted¹¹⁹ output-weighted-average CO₂ emission rates

¹¹⁹ As described below, the emission rate goals include adjustments to incorporate the potential effects of emission reduction measures that address power sector CO₂ emissions primarily by reducing the amount of electricity produced at a
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. In addition, states have discretion to adopt and submit different forms of standards of performance, as long as the submittal achieves a level of performance (including timing) at least equivalent to the goal. For example, we anticipate that some states may prefer to adopt mass-based standards of performance in which performance is gauged in terms of the mass of CO₂ emissions from affected units rather than in terms of the amounts of CO₂ emitted per unit of energy output produced by those units. Likewise, although the proposed goals are state-specific, we anticipate that some states may prefer to submit plans reflecting a multi-state approach for complying with standards of performance.

At this time the EPA is not proposing targets for either tribal lands or territories. EPA does believe it is appropriate to eventually require targets for both tribal lands and territories.

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 CO₂ emission rates per unit of energy output produced.
With respect to tribal lands, EPA is soliciting comment on the application of the four BSER building blocks to determine a CO₂ performance standard for units on individual tribal lands. Also, for tribes wishing to include the EGUs on their tribal lands in a multi-state plan (i.e., treating the tribal lands as an additional state) we are soliciting comment on how to adjust the multi-state plan goal to accommodate the addition of EGUs on tribal land. EPA also recognizes that in several cases, regional haze BART requirements may lead to significant CO₂ reductions. EPA is soliciting comment on whether and how those actions should factor into setting tribal targets.

With respect to territories, EPA takes comment on the appropriateness of the four building block approach for territories. In particular, the EPA takes comment on appropriate alternatives for territories that do not have access to natural gas as well as on ways to determine appropriate renewable targets in the absence of the types of regional data used to develop the renewable component of BSER for states. The remainder of this section addresses four 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. Finally, we describe the
alternate set of goals offered for comment and certain other approaches we considered.

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 CO₂ emission rates that the affected fossil fuel-fired EGUs located in each state could achieve through implementation of the four building blocks (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 CO₂ 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 CO₂ 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 CO₂ emissions by reducing the quantity of fossil fuel-fired
generation rather than by reducing the CO₂ 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 types of goals presents advantages. 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

Comment [A201]: As highlighted in previous comments, severability may be more easily supported if EPA could identify what percentages of each building blocks contributes to the overall goal.
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 CO₂ emissions by shifting generation among different types of EGUs within a state.

Specifically, because CO₂ 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 provide 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 CO₂ emission reductions can be achieved by shifting generation from EGUs with higher CO₂ emission rates, such as coal-fired EGUs, to EGUs with lower CO₂ emission rates, such as NGCC units. Our analysis indicates that shifting generation among EGUs is a potentially large source of cost-effective CO₂ emission reductions for the power sector. 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 associated with measures such as increases in low- and zero-carbon generating capacity and demand-side energy efficiency. We recognize that overall CO₂ emissions from affected EGUs are reduced by reducing generation from those EGUs collectively rather than by reducing the CO₂ emission rates of affected EGUs or by shifting generation from the most carbon-intensive affected EGUs to less carbon-intensive 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 avoid 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 CO₂ emissions\textsuperscript{120} rather than on CO₂ emission rates, because the emission-reducing effects of reduced utilization of affected EGUs are evident in the EGUs’ reported CO₂ mass emissions.

The fourth aspect noted above concerns the proposed expression of the goals in terms of net energy output – that is, energy output encompassing net MWh generation measured at the point of delivery to the transmission grid rather than gross MWh generation measured at the EGU’s generator.\textsuperscript{121} (As discussed below in section VIII on state plans, we are similarly proposing

\textsuperscript{120} 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 CO₂ emissions in another state. These issues are discussed below in section VIII on state plans.

\textsuperscript{121} For some EGUs, total net or gross energy output also includes useful thermal output, in addition to either net or gross electric energy output.
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.) 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. Improvements in the efficiency of these devices represent opportunities to reduce carbon intensity at affected EGUs that would not be captured in measurements of emissions per gross MWh. Further, nearly all EGUs already have in place the equipment necessary to determine and report hourly net MWh 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\textsuperscript{122} to us under 40 CFR Part 75, and that the proposed GHG standards of performance for new EGUs are expressed in terms of gross MWh generation (although we sought comment on the use of net MWh generation instead). We therefore specifically seek comment on whether the goals and reporting requirements for existing EGUs should be expressed in terms of gross MWh generation instead of net MWh generation for consistency with existing reporting requirements and with the

\textsuperscript{122} Some EGUs report gross steam output instead of gross load.
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 are independent of each other and the goals are the sum of the emission reductions from all of the building blocks, if any of the building blocks are found to be invalid bases for the “best system of emission reduction ... adequately demonstrated,” the goals would be adjusted to reflect the emissions reductions from the remaining building blocks.

We invite comment on all aspects of the proposed form of the goals, including suggestions for specific alternative forms of goals not discussed above that may also merit consideration.

C. Proposed goals and computation procedure

The EPA has developed proposed goals for state plans reflecting use of all four building blocks described earlier. The goals are intended to represent CO₂ 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 emission reductions by avoiding fossil generation. In addition to the final goals, EPA has developed
interim goals that would apply during the 2020-2029 period on a cumulative or average basis as states progress toward the final goals. (The issue of how states could demonstrate emission performance consistent with the goals is addressed in Section VIII on state plans.) The proposed goals are set forth in Table 5 below.

**Table 5: Proposed State Goals (Adjusted Output-Weighted-Average Pounds of CO₂ Per Net MWh From All Existing Affected Fossil Fuel-Fired EGUs)**

<table>
<thead>
<tr>
<th>State</th>
<th>Interim Goal</th>
<th>Final Goal</th>
</tr>
</thead>
<tbody>
<tr>
<td>Alabama</td>
<td>1,113</td>
<td>1,024</td>
</tr>
<tr>
<td>Alaska</td>
<td>1,039</td>
<td>878</td>
</tr>
<tr>
<td>Arizona*</td>
<td>724</td>
<td>691</td>
</tr>
<tr>
<td>Arkansas</td>
<td>1,012</td>
<td>950</td>
</tr>
<tr>
<td>California</td>
<td>580</td>
<td>558</td>
</tr>
<tr>
<td>Colorado</td>
<td>1,164</td>
<td>1,112</td>
</tr>
<tr>
<td>Connecticut</td>
<td>588</td>
<td>533</td>
</tr>
<tr>
<td>Delaware</td>
<td>922</td>
<td>848</td>
</tr>
<tr>
<td>Florida</td>
<td>750</td>
<td>692</td>
</tr>
</tbody>
</table>

123 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, EPA is not proposing goals for tribes or U.S. territories at this time.
<table>
<thead>
<tr>
<th>State</th>
<th>First Year</th>
<th>Second Year</th>
</tr>
</thead>
<tbody>
<tr>
<td>Georgia</td>
<td>885</td>
<td>826</td>
</tr>
<tr>
<td>Hawaii</td>
<td>1,388</td>
<td>1,304</td>
</tr>
<tr>
<td>Idaho</td>
<td>241</td>
<td>225</td>
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<tr>
<td>Illinois</td>
<td>1,391</td>
<td>1,293</td>
</tr>
<tr>
<td>Indiana</td>
<td>1,627</td>
<td>1,549</td>
</tr>
<tr>
<td>Iowa</td>
<td>1,351</td>
<td>1,310</td>
</tr>
<tr>
<td>Kansas</td>
<td>1,597</td>
<td>1,516</td>
</tr>
<tr>
<td>Kentucky</td>
<td>1,861</td>
<td>1,778</td>
</tr>
<tr>
<td>Louisiana</td>
<td>1,080</td>
<td>993</td>
</tr>
<tr>
<td>Maine</td>
<td>423</td>
<td>407</td>
</tr>
<tr>
<td>Maryland</td>
<td>1,325</td>
<td>1,166</td>
</tr>
<tr>
<td>Massachusetts</td>
<td>646</td>
<td>567</td>
</tr>
<tr>
<td>Michigan</td>
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<td>1,261</td>
</tr>
<tr>
<td>Minnesota</td>
<td>891</td>
<td>851</td>
</tr>
<tr>
<td>Mississippi</td>
<td>717</td>
<td>673</td>
</tr>
<tr>
<td>Missouri</td>
<td>1,621</td>
<td>1,544</td>
</tr>
<tr>
<td>Montana</td>
<td>1,900</td>
<td>1,781</td>
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<tr>
<td>Nebraska</td>
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<td>1,471</td>
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<tr>
<td>Nevada</td>
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<td>644</td>
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<tr>
<td>New Hampshire</td>
<td>542</td>
<td>485</td>
</tr>
<tr>
<td>New Jersey</td>
<td>657</td>
<td>531</td>
</tr>
<tr>
<td>New Mexico *</td>
<td>1,088</td>
<td>1,000</td>
</tr>
<tr>
<td>State</td>
<td>2015</td>
<td>2014</td>
</tr>
<tr>
<td>----------------</td>
<td>------</td>
<td>------</td>
</tr>
<tr>
<td>New York</td>
<td>647</td>
<td>557</td>
</tr>
<tr>
<td>North Carolina</td>
<td>1,064</td>
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</tr>
<tr>
<td>North Dakota</td>
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<td>Ohio</td>
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<td>Oklahoma</td>
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<td>879</td>
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<td>Oregon</td>
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<td>Pennsylvania</td>
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<td>Rhode Island</td>
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<td>773</td>
</tr>
<tr>
<td>South Carolina</td>
<td>802</td>
<td>736</td>
</tr>
<tr>
<td>South Dakota</td>
<td>794</td>
<td>731</td>
</tr>
<tr>
<td>Tennessee</td>
<td>1,234</td>
<td>1,142</td>
</tr>
<tr>
<td>Texas</td>
<td>932</td>
<td>855</td>
</tr>
<tr>
<td>Utah *</td>
<td>1,375</td>
<td>1,318</td>
</tr>
<tr>
<td>Virginia</td>
<td>869</td>
<td>793</td>
</tr>
<tr>
<td>Washington</td>
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<td>235</td>
</tr>
<tr>
<td>West Virginia</td>
<td>1,766</td>
<td>1,636</td>
</tr>
<tr>
<td>Wisconsin</td>
<td>1,265</td>
<td>1,185</td>
</tr>
<tr>
<td>Wyoming</td>
<td>1,801</td>
<td>1,701</td>
</tr>
</tbody>
</table>

* Excludes EGUs located in tribal areas in 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 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 emission reductions. The adjustment is made by estimating the annual net MWh generation associated with an achievable amount of qualifying new low-carbon and zero-carbon generating capacity, as well as the annual avoided MWh 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. Mathematically, this adjustment has the effect of spreading the measured CO₂ 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 measures that increase low- or zero carbon generating capacity or demand-side energy efficiency.)

124 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.
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 CO₂ emissions, net MWh generation, and MW capacity from reported 2012 data for all affected EGUs.125 For each state, we aggregated the 2012 data for all coal-fired steam EGUs as a group, all oil- and gas-fired steam EGUs as a group, all NGCC units as a group, and all remaining affected EGUs as a group (i.e., integrated gasification combined-cycle (IGCC) units and any simple-cycle combustion turbines satisfying the size and electricity sales

125 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 turbines were excluded on this basis. See the applicability criteria described in Section V.A. above.
thresholds for qualification as affected EGUs). 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. 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 CO₂ 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 technically achievable and cost-effective opportunity to reduce CO₂ emission rates across the existing fleet of coal-fired steam EGUs through heat rate improvements.

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).
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 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 MWh 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 CO₂ emission rates, to the NGCC group, which has a lower CO₂

127 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.
emission rate, the total (across all four groups) of the state’s CO₂ emissions was reduced.128

Step 4 (application of building block 3). We estimated the total quantities of new renewable capacity and new or preserved nuclear capacity that would be made available in each state under “best practices” approaches to renewable and nuclear capacity, and we estimated the MWh generation from this incremental low- or zero-carbon generating capacity based on historic utilization rates for units of the same types.

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 by implementation in that state of a comprehensive “best practices” approach to 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. 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

128 We did not estimate any change in utilization, generation, or emissions for the state’s group of IGCC units and simple-cycle combustion turbines in Step 3.
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 CO₂ emission rates for each state by dividing (1) the total CO₂ 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 MWh generation from new 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. We performed these computations separately for each year from 2020 to 2029, using the respective cumulative annual MWh savings figures developed in Step 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.) 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 should we 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 blocks 3 and 4, we specifically request comment on the following alternative procedure: in Steps 4 and 5, should we estimate the quantity of generation reductions and associated emission reductions at the state’s affected EGUs that would be achieved through application of these building blocks and then, in Step 6, subtract these emission reduction quantities from the numerator of the adjusted emission rate equation (instead of computing the quantities of generation that would be produced by new low-carbon capacity and avoided by demand-side energy efficiency and then adding those generation quantities to the denominator of the adjusted emission rate equation)? Further, under this alternative approach for building blocks 3 and 4, should we estimate the emission reductions at the state’s affected EGUs by decreasing generation from the coal-fired steam group first or instead by decreasing generation proportionately from the coal-fired steam and oil/gas-fired steam groups?

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
D. State flexibilities

States' ability to achieve emission performance levels consistent with the goals is enhanced by several distinct types of flexibility: (i) choices as to the measures employed, including timing; (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 interstate compliance 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.
Further, by allowing states to demonstrate compliance over a
multi-year plan period of as long as ten years, the emission
guideline increases states’ flexibility to choose among
alternative potential 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
remaining useful life, for example, by enabling them to defer
imposition of requirements on EGUs that may be scheduled to
retire after 2020 but before 2029.

Second, as noted earlier, 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 states that currently participate in the mass-based
Regional Greenhouse Gas Initiative (RGGI) may choose to develop
state plans 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 CO₂ emissions budget program. Because the use of mass-based plans can simplify the process of accounting for the CO₂ 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 programs as well.

Third, the emission guidelines allow 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 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 demonstrating equivalency between the two forms and issues related to multi-state plans are discussed below in section VIII on state plans.

Some stakeholders have suggested that states themselves should have flexibility to quantify the level of emission reduction resulting from the application of BSER. Consistent with the existing framework regulations, we view this
quantification as the EPA’s role,\textsuperscript{129} and we do not propose to re-open that portion of the framework regulations in this rulemaking. By the same token, because the state goals are an integral part of the emission guidelines that the framework regulations authorize EPA to establish, the states, in their section 111(d) plans, must meet those goals, and may not make them less stringent. This matter, too, is resolved by the framework regulations,\textsuperscript{130} and EPA is not re-opening it in this rulemaking. To reiterate, the goals are intended to demonstrate a level of performance achievable through application of the building blocks considering the unique circumstances of each individual state that would be acceptable in a state plan. States 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, and they can use rate-based or mass-based approaches. In addition, we note that multi-state coordination offers states an opportunity to achieve additional emission reductions and reduce implementation costs.

We solicit comment on whether, and, if so, when and under what circumstances the EPA should consider adjusting a state-specific goal in response to a state’s request on grounds that

\textsuperscript{129} 40 CFR 60.22(b)(5).
\textsuperscript{130} 40 CFR 60.22(b)(5).
the goal does not reflect BSER as applied in that state. Specifically, should a request made after the comment period in the rulemaking be considered at all? Should a request made after issuance of the final rule be considered? Should a post-comment period request be considered if it is based on information that could have been provided during the comment period? What materiality thresholds should EPA apply to adjustment requests? Should the state be required to demonstrate that it would be unable to achieve the goal as set by EPA, even after considering all of the building blocks and all of the flexibilities available to the state discussed above regarding the selection of measures, the form of the goal, and the multi-year period to reach the final goal? Should the state be required to demonstrate that it would be unable to achieve the goal even after consideration of multi-state approaches? What could suffice for a demonstration that the goal does not represent BSER?

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.

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 best practices portfolio of demand-side energy efficiency programs in Step 5. (No change was made to the data inputs regarding new 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 6 below.
Table 6: Alternate State Goals (Adjusted Output-Weighted-Average Pounds of CO₂ Per Net MWh From All Affected Fossil Fuel-Fired EGUs)

<table>
<thead>
<tr>
<th>State</th>
<th>Interim Goal</th>
<th>Final Goal</th>
</tr>
</thead>
<tbody>
<tr>
<td>Alabama</td>
<td>1,243</td>
<td>1,208</td>
</tr>
<tr>
<td>Alaska</td>
<td>1,142</td>
<td>1,086</td>
</tr>
<tr>
<td>Arizona *</td>
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<tr>
<td>Arkansas</td>
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<td>1,101</td>
</tr>
<tr>
<td>California</td>
<td>611</td>
<td>599</td>
</tr>
<tr>
<td>Colorado</td>
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<td>1,232</td>
</tr>
<tr>
<td>Connecticut</td>
<td>640</td>
<td>617</td>
</tr>
<tr>
<td>Delaware</td>
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<td>1,010</td>
</tr>
<tr>
<td>Florida</td>
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</tr>
<tr>
<td>Georgia</td>
<td>992</td>
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<tr>
<td>Hawaii</td>
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<tr>
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<td>Illinois</td>
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<td>Indiana</td>
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<td>Iowa</td>
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<tr>
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<tr>
<td>Kentucky</td>
<td>1,971</td>
<td>1,937</td>
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</table>

131 See footnote accompanying Table VII.C-1 above.
<table>
<thead>
<tr>
<th>State</th>
<th>Value 1</th>
<th>Value 2</th>
</tr>
</thead>
<tbody>
<tr>
<td>Louisiana</td>
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<tr>
<td>Maine</td>
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<td>440</td>
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<td>Maryland</td>
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<tr>
<td>Massachusetts</td>
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<tr>
<td>Michigan</td>
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<tr>
<td>Minnesota</td>
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<tr>
<td>Mississippi</td>
<td>754</td>
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<tr>
<td>Missouri</td>
<td>1,726</td>
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<tr>
<td>Montana</td>
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<td>Nebraska</td>
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<tr>
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<tr>
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<tr>
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<td>715</td>
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<tr>
<td>North Carolina</td>
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<td>Oregon</td>
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<td>Pennsylvania</td>
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<td>Rhode Island</td>
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<td>837</td>
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<tr>
<td>State</td>
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<td>2015</td>
</tr>
<tr>
<td>------------------</td>
<td>-------</td>
<td>-------</td>
</tr>
<tr>
<td>South Carolina</td>
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<tr>
<td>South Dakota</td>
<td>885</td>
<td>856</td>
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<td>Tennessee</td>
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<td>Utah *</td>
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<td>Washington</td>
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<td>West Virginia</td>
<td>1,877</td>
<td>1,835</td>
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<tr>
<td>Wisconsin</td>
<td>1,404</td>
<td>1,366</td>
</tr>
<tr>
<td>Wyoming</td>
<td>1,902</td>
<td>1,862</td>
</tr>
</tbody>
</table>

* Excludes EGUs located in tribal areas in the state.

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 the estimated opportunities to reduce utilization of the most carbon-intensive EGUs by shifting generation to less carbon-intensive EGUs should be based on regional evaluations rather than state-specific evaluations. A potential advantage of using regional evaluations is the ability to recognize additional cost-effective emission
reduction opportunities based on a more complete representation of the capabilities of existing infrastructure to accommodate shifts in generation among EGUs in multiple states. On the other hand, it could be argued that states might have less flexibility to adopt plans that take different approaches than neighboring states if the goals are set at levels that reflect the ability to capture emission reduction opportunities that require interstate cooperation. We request comment on whether, and if so how, the EPA should incorporate greater consideration of regional approaches into the goal-setting process, and on the issue of whether, and if so how, the potential cost savings associated with regional approaches may be considered in assessing the cost effectiveness 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 is sympathetic to this concern, and so in designing this program the EPA has paid careful attention to this issue. 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 of the power system. EPA staff and managers have also had numerous discussions with state public utility commissioners and
their staff to get their suggestions and advice concerning this rule including how to address reliability concerns.

In addition, the EPA met with the independent system operators several times to discuss any potential impact of this rule on grid reliability. The ISO/RTO Council, a national organization of these entities, 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. These suggestions are described elsewhere in this preamble and we welcome comment on them.

EPA has discussed this issue with the US Department of Agriculture as well to discuss how we can address the concerns of small 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 BSER, looked specifically at the cost effectiveness of control options in part to assure that the option would not have a negative effect on system reliability. Each of the building blocks was determined to be cost effective. Further, the states under the
Clean Air Act are given the flexibility to design state plans that include any measure or combination of measures to achieve that emissions limitation. States are not required to use each of the measures that the EPA determines constitute BSER or use those measures to the same degree of stringency that the EPA determines is achievable and cost-effective. Thus each state has the flexibility to choose measures that are cost effective given that state’s energy profile and economy as long as the state achieved the reductions necessary to meeting 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. Regional approaches as well, 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, actually reduce demand for centrally generated power and thus relieve pressure on the grid.

Because the EPA is proposing a 10-year period over which to achieve the full required CO2 reductions we would expect would
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. In addition, states can 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 without jeopardizing the grid.

The EPA’s supporting analysis for this rule includes an examination of the effects of the rule on regional resource adequacy. 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 these 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 horizon for compliance with this rule will permit environmental and reliability planners to coordinate these changes and address potential concerns before they arise.

Comment [A214]: In addition to resource adequacy, has there been any analysis/considerations of potential seams issues or related inefficiencies/power prices due to different state/regional approaches (e.g., potential for similar units to have drastically different prices in neighboring states due to different state approaches)?
The EPA concludes that the proposed rule will not raise significant concerns over regional resource adequacy or raise the potential for interregional grid problems. EPA believes 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 CO₂ 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 CO₂ goal set by the EPA or translate the rate-based goal to a mass-based goal.

The state must then establish a standard of performance or set of standards of performance, 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 plans 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, then the EPA must establish a plan.

In the case of a tribe that has one or more affected EGUs on its lands, the tribe would have the opportunity, but not the obligation, to establish a CO₂ performance standard and a plan for its tribal lands. Consequently, developing a section 111(d) tribal plan is optional for tribes. The CAA allows the EPA to treat tribes in the same manner as states for the purpose of implementing CAA programs, while providing flexibility for tribes to develop a program tailored to their specific circumstances. A tribe that develops a section 111(d) tribal plan will actively contribute to helping reduce greenhouse gas emissions. Though the EPA is aware of three coal-fired EGUs located on tribal lands, the agency is not proposing specific goals for tribes with affected EGUs in this action at this time.
EPA will coordinate with those tribes wishing to develop and implement a section 111(d) tribal plan by determining BSER for the section 111(d) affected units on tribal lands. If a tribe chooses not to submit a plan, or if the EPA does not approve a tribe’s plan, then the EPA must establish a plan for affected EGUs on tribal lands.

This section is organized into five parts. First, we discuss the proposed overall approach to state plans, with a focus on the different types of plans that we propose to authorize states to submit, and address timing for achievement of the required level of emission performance. Second, we discuss the proposed state plan approvability criteria. Third, we summarize the proposed components of an approvable state plan. Fourth, we address the proposed process and timing for submittal of state plans and for demonstrating progress and compliance with the emission performance levels in the state plans. Fifth, 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 responsible parties; treatment
of interstate effects; and, projecting emission performance. Finally, we discuss a number of additional factors that can help states meet their CO₂ emission performance goals, and we note certain resources we are making 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 Emission Performance: Mass-Based Goals and Plan Performance TSD, both of which are in the rulemaking docket.

B. Approach

In this action, the EPA is proposing emission guidelines for states to use in developing plans to establish and implement CO₂ standards of performance for affected EGUs. In addition to the proposed state-specific goals described in the Section VII of this preamble, the proposed emission guidelines include twelve required components for a state plan to be approvable and the process and timing for state plan submittal and review and for achievement of the CO₂ goal. 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 proposed emission guidelines provide states with options for establishing performance standards in a manner that accommodates a diverse range of state approaches. The proposed emission 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 state measures may impact and, in fact may be explicitly designed to reduce, regional EGU CO₂ emissions.

1. State plan approaches
   a. Overview

   The diversity of measures that qualify as the BSER indicates that different types of state plans under section 111(d) could be constructed, and the EPA’s outreach efforts has made clear that in fact, states are considering different types of plans. An important issue common to all types of plans is whether the plan should require the affected EGUs to be responsible for assuring that the emissions performance level is achieved, or instead, whether the plan could rely on measures imposed on entities other than affected EGUs to assure that at least part of that level is achieved. A second important issue concerns the fact that requiring all measures relied on to achieve the emissions performance level to be included in the
state plan renders those measures federally enforceable. In light of current state programs, along with stakeholder concerns over those issues and legal considerations, the EPA is proposing to authorize state plans that do not hold the affected EGUs fully responsible for achieving the emissions performance level. In addition, the EPA is soliciting comment on several other types of state plans that may assure the requisite level of emissions performance without rendering certain types of measures federally enforceable and to 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 designed to reduce CO₂ emissions from fossil-fired power plants. Existing state programs are particularly informative for this purpose in light of the fact that 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 reduced utilization of, and therefore reduced emissions from,
fossil-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-fired EGUs would be required to bear for the required emissions reductions, in particular, those from reduced utilization 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-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 the “portfolio approach,” in which the plan would include emission limits for affected EGUs along with other enforceable RE and demand-side EE measures that reduce utilization of affected EGUs and thereby avoid CO₂ emissions. Under this approach, all of the measures combined would be designed to achieve the required emission performance level for affected EGUs. However, the emission limits enforceable against the affected EGUs would not, on their own, 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 CO₂ emissions 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 emissions 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 “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 CO₂ emissions. Under a state-driven approach, the measures in a state plan would include requirements that apply directly to entities other than affected EGUs, for example, renewable portfolio standards

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132 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.
or end-use energy efficiency resource standards (EERS), both of which often apply to electric distribution utilities.\textsuperscript{133}

It should be evident that these plan approaches differ substantially in the mechanics used to achieve the required level of emission performance for affected EGUs, including necessary plan elements and the relative degree of plan complexity. The plan approaches also differ with regard to the party or parties that are responsible for achievement of the required level of emission performance. As a result, a state may develop an approach for cost-effectively reducing EGU CO\textsubscript{2} emissions that best suits its circumstances and may select whether elements of the state approach are enforceable components of a plan or complementary to an enforceable measure in a plan.

c. Obligations on affected EGUs

Although the EPA is proposing to authorize state plans to adopt the portfolio approach, we are mindful that it presents a legal issue that bears further analysis. We describe, and solicit comment on, that issue below. In brief, it may be possible to read CAA §111(d)(1) as requiring that when EPA

\textsuperscript{133} 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 generation assets.
promulgates emission guidelines to achieve emission reductions from a particular source category, thereby triggering state obligations to adopt plans that include standards of performance as well as implementing and enforcing measures, the standards of performance must impose the responsibility for achieving the required emissions reductions on the sources in the affected source category. Accordingly, again as noted below, we are soliciting comment on whether state plans must require the affected EGUs to be legally responsible for achieving the emissions performance level.

We note that some existing state programs, such as RGGI in the northeastern states, do impose the ultimate responsibility on fossil-fired EGUs to achieve the required reductions, but are also designed to work either concurrently, or in an integrated fashion, with RE and demand-side EE programs that reduce cost. These existing programs offer a possible precedent for another type of section 111(d) state plan. Such a plan could rely on CO₂ emission limits enforceable against affected EGUs to ensure achievement of the required emission performance level, but also include enforceable RE and demand-side EE measures that lower cost and otherwise facilitate EGU emission reductions. In this manner, RE and demand-side EE measures could be a major
component of a state’s overall strategy for cost-effectively reducing EGU CO₂ emissions.\footnote{It should be noted that state plans that impose legal responsibility on the affected EGUs to achieve the full level of required emissions performance could incorporate enforceable RE and demand-side EE measures regardless of whether the standards of performance that those plans apply to the affected EGUs take the form of an emissions 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 CO₂ emission rate when demonstrating compliance through either an administrative adjustment by the state or use of a tradable crediting 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 relies on mass-based emission limits would be federally enforceable through the standard of performance that applies to an affected EGU itself (i.e., enforceable against the EGU). Such a plan would not need to make any adjustment or crediting to account for RE or demand-side EE measures.}

d. Federal enforceability

We are also cognizant of another concern expressed by some stakeholders, which 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 this point, largely have been the reserve of the state and, in particular, state public utility commissions. These stakeholders point out 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 section 111(d) state plan. Under those
circumstances, the measures would not be enforceable under federal law, but 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, 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 section 111(d) state plan, even without including those measures in the plan.

e. Plans with state commitments

As a vehicle for approving 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 may 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
emissions reductions of behalf of affected EGUs. The agency requests comment on the legal authority for 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 emissions 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 legal responsibility on affected EGUs for ensuring the emissions 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 emissions performance level on the affected EGUs, but the state would credit the EGUs with the amount of emissions 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.
discussed above. We solicit comment on whether, if the EPA were to conclude that section 111(d) requires state plans to include standards of performance applicable to affected EGUs that achieve the emissions 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 required to promulgate emission guidelines for state plans to address emissions from sources in a source category for which the EPA has promulgated requirements under CAA section 111(b). CAA section 111(d)(1) requires that the state plans “(A) establish[] standards of performance for any existing source [for certain air pollutants] . . . and (B) provide[] 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, important issues in this rulemaking concern whether
such emission limits are the only mechanisms that state plans may include for achieving the emissions performance level, and whether only affected EGUs may be subject to requirements associated with reducing their emissions. The resolution of those issues depends on whether the state plan requirements in section 111(d)(1), quoted above, are interpreted so that the only measures that may be included in a state plan are standards of performance and measures that implement and enforce those standards, so that the standards of performance must apply to the sources in the source category; and whether the definition in section 111(a)(1) is interpreted so that the standards of performance must consist of emission limitations and must achieve the full degree of emission limitation that results from application of BSER.

Specifically, we solicit comment on interpretations of these provisions that would authorize the portfolio approach described above. First, we solicit comment on whether state plans are limited to standards of performance and measures that implement and enforce those standards. Specifically, although section 111(d)(1) does not identify any types of measures other than those ones, does it preclude state plans from including other measures? Interpreting section 111(d)(1) to include other
measures could provide a basis for the portfolio approach described above.

Second, we solicit comment on whether the requirement that the plan include “standards of performance for [affected sources]” could be interpreted to include the emissions performance level - that is, the adjusted, average emission rate for affected EGUs in the state - 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. Interpreting the requirement in this manner could provide a basis for the portfolio approach because RE and demand-side EE measures could be considered measures that implement the emissions performance level.

Third, we solicit comment on whether the requirement that the plan include “standards of performance for [affected sources]” could be interpreted to include measures such as RE and demand-side EE measures, even if they may not directly reduce emission rates of the affected EGUs or are not enforceable against the affected EGUs, on grounds that they are associated with reducing CO₂ emissions from affected EGUs.

Fourth, the EPA is soliciting comment on whether measures such as RE and demand-side EE measures, even if they are not
enforceable against the affected EGUs, may be included in the state plan as measures that “implement[] and enforce[]” the plan’s standards of performance. For example, if the plan achieves the emissions performance level through rate-based emission limits applicable to the affected sources, coupled with a crediting mechanism for RE and demand-side EE measures, it may be argued 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 whether measures such as RE and demand-side EE may be considered “implement[ing]” measures in state plans if they are not associated with emission reductions that affected sources are required, through emission limits, to make.

Finally, the EPA solicits comment on whether state plans may include, either as standards of performance or as “implement[ing]” measures, requirements on entities other than the affected sources.

The EPA solicits comment on all legal issues under CAA section 111(d)(1) with respect to the approaches described in this section and in the discussion above on types of state plans and measures.

2. Timing for implementation and achievement of goals
This section addresses the process and timing for demonstrating achievement of emission performance goals and compliance with the emission performance levels in the state plans.

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 carbon emissions, particularly blocks 3 (expansion of cleaner generation 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 RE generation over time. As such, 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 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 benefit to 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 reductions between 2020 and 2030 as long as a cumulative overall emission reduction target is met.

The subsections below contain proposals for: a) a more thorough discussion of the time period covered by state plans, b) the start date for the interim goal performance period, c) the duration of the performance periods for the final and interim goals, d) interim progress milestone requirements, and e) out-year requirements for states to maintain over time CO₂ emission performance levels consistent with the final goal. The agency also is requesting comment on alternative requirements aimed at continued emission performance improvement after 2029. Section [VII. F] proposes flexibility from states to change from mass-based to rate-based goals in different performance periods, and subsection [VII.G] takes comment on planning requirements that match the agency’s alternative, less stringent state goals.

a. Time period covered by state plans

As described previously, the agency is proposing final state-specific goals (specified in Table 5) that represent emission rates achievable by 2030, as well as interim goals, achievable on average over the 10-year period from 2020-2029.
The agency is also proposing that the final state-specific goals be maintained from 2030 and thereafter.

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 regulated entities will have an ongoing relationship in the course of implementing this program.

The EPA proposes that a state plan must demonstrate achievement of the emission performance levels in the plan, and these emission performance levels must be equivalent to the interim and final goals established by the EPA. In its plan, the state must also demonstrate that performance meeting the final goal will be maintained beyond 2030.

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. Also, if the state plans address both achievement and maintenance of the goals, additional state submittals may be simpler and, for some states, unnecessary, depending on the nature of state programs and out-year requirements.

The EPA recognizes that the proposed approach requires states to make projections regarding electricity demand, supply, and capacity utilization of individual units, as well as the estimated effect of state measures included in a plan, for a lengthy period of time into the future. Therefore, the agency also is requesting comment on alternative approaches.

The agency requests comment on a second option in which state plans would be required to demonstrate achievement of the interim and final goals but would not be required to demonstrate that the final emission performance level will be maintained over time. Instead, states would be required to make a submittal in 2025 showing whether their plan measures would maintain the

135 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 BSER-based level is a more stringent level than the 2020-2029 average BSER-based level. The purpose of the final goal to be achieved and maintained is to ensure that each state ultimately achieves the emissions performance level for affected EGUs that is achievable by 2029 through application of BSER. Depending on the emission performance improvement trajectory required by a state plan, a state plan that will achieve the 2020-2029 interim goal may or may not also result in meeting the 2030 final goal.
final-goal level of performance over time (under one of the out-year approaches described in the relevant section below). If not, the state submittal would be required to add to the state plan additional measures necessary to maintain that level of performance over time.

The agency also requests comment on a third option in which the state plan would focus on the interim goal only. Because state plans may underperform with regard to the interim goal in the early years of the 10-year period and outperform the interim goal in the latter years of the period, the plan measures that a state implements by the last part of the interim goal period may be sufficient to achieve the final goal as well. Under this option, the state would make a second plan submittal in 2025 to demonstrate that the final goal will be met by existing plan measures. If not, the state submittal would be required to strengthen the state plan with additional measures so that the plan will achieve the final goal and maintain that level of performance thereafter.

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 and third options.

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 2020 for the performance period. 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 regulated entities may have greater lead time for compliance than might be implied by the plan submittal dates referenced above. Regulated 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 EPA. Also, as explained in detail in subsection c,

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136 The start date for a plan performance period must match the start date of the corresponding state emissions 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.
states may choose a different emissions performance improvement trajectory than EPA assumes for purposes of calculating goals, achieving less in early years and more in later years.

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 emissions performance levels. Second, in advance of this proposal, many states already were contemplating design of strategies for meeting the requirements of section 111(d). Third, for inclusion in the building blocks, the EPA considered only those abatement measures that are technically viable and broadly applicable, and can provide cost-effective reductions in CO₂ emissions from affected existing EGUs.

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 O&M and engineered 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 CO₂ emissions
from existing EGUs. HRI “best practices” (e.g., installation of modern control systems, operator training, smart soot blowing) are the least cost 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 outages, 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) over a four-year period concluding in 2020.

Dispatch changes, which are largely driven by the variable cost of operating a given electric generating unit, 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 (source: NERC, 2008-2012 Generating Unit Statistical Brochure). 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 CO2 reductions at existing EGUs by the 2020 compliance start date.

Building Block 3 is based on shifting generation from steam fossil units to new renewable energy 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 provide cost effective reductions in CO2 emissions from existing EGUs. The 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 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 the goal sooner. Each
state’s current level of performance is taken into account, with state’s 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 CO₂ 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 emissions 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 due to 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.

Comment [A219]: It may be worth mentioning that New programs also often have the benefit of more potential available to capture
As described in Section VII of the preamble, the EPA is proposing state-specific CO₂ emission performance goals in a multi-year format to provide states with flexibility for the timing of programs and measures that improve EGU emissions performance, while ensuring an overall level of performance consistent with the application of BSER. Specifically, the agency is proposing the state-specific goals (shown in Table 5) which represent emission rates to be achieved by 2030 (final goal) and emission rates achievable on average over the 2020-2029 period (the interim goal).

The EPA proposes the following Option A as the preferred option for the final and interim goal performance periods. A state plan must demonstrate that the statewide emission performance of affected EGUs will meet the interim emission performance level on average over the 2020-2029 period. Similarly, the EPA proposes that plan measures must initially achieve the final emission performance level by 2030, as reflected by a 3-year average over the 2030-2032 period.

This proposed approach provides a 10-year performance period for the interim performance level, and a three-year performance period for the final performance level. The 10-year interim performance period allows states flexibility for timing of program implementation as the state ramps up its programs to

Comment [A220]: Why doesn’t EPA average over 2029-2031 for measuring the 2030 performance?
achieve the final performance level. The three-year performance period for initial achievement of the final performance level is proposed in light of year-to-year variability in economic and other factors, such as weather, that influence power system operation and affect EGU CO₂ emissions.

For a rate-based plan, 2020-2029 emission performance is an average CO₂ emission rate for affected EGUs representing cumulative CO₂ emissions for affected EGUs over the course of the 10-year performance period divided by cumulative MWh energy output from affected EGUs over the 10-year performance period, with rate adjustments for qualifying end-use energy efficiency and renewable energy measures as described in Section VIII.E. For a mass-based plan, 2020-2029 emission performance is total tons of CO₂ emitted by affected EGUs over the ten-year performance period.

As noted, a 10-year performance period -- with a demonstration of average or cumulative performance over the period -- offers states flexibility in the timing of emission improvements. However, to ensure accountability throughout the course of the 10-year period, the EPA is proposing that certain

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137 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.
types of state plans include interim progress milestones, as described in Section VIII.A.2.c of this preamble.

The EPA requests comment on a second approach, Option B, to state plan performance periods. Option B is the same as Option A except that, in addition to the requirements for Option A, a state plan also would need to achieve a 5-year average emission performance level reflecting application of BSER for the 2020-2024 period. This 5-year performance period would nest within the 10-year performance period for the 2020-2029 period. The purpose of Option B would be to ensure greater emission performance improvement during the first five years by precluding states from significantly delaying compliance obligations until the last five years. However, Option B also would reduce states’ flexibility for the timing of emission improvements over the 2020-2029 period.

The agency invites comment on any other approaches to specifying performance periods for state plan.

d. Interim progress milestones

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
programmatic milestones to ensure interim progress, as well as periodic checks on overall emissions performance leading to corrective action if necessary.

Some types of plans inherently would assure interim performance and full achievement of the state plan’s required level of performance through requirements that are enforceable against affected EGU, and we refer to these as “self-correcting” plans. One example would be a state plan with a rate-based emission performance level that requires affected EGUS collectively to meet, on a three-year average basis, a statewide 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., limits that apply to 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 the full level of required emission performance in a manner that is federally enforceable against affected EGUs.

For plans that are not self-correcting, the EPA proposes that the state plan must identify periodic programmatic milestones (e.g., start of an end-use energy efficiency program, retirement of an affected EGUs, 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 programmatic milestones in its plan, the EPA would evaluate actions under CAA authorities to ensure timely program implementation.

In addition, we propose that the state and the EPA would check emission performance achieved versus performance projected in the state plan at least every two years. If actual emission performance is not within 10 percent of original projections, the state would be required to submit a report to the EPA within 6 months of the two-year check point. The report would 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 actions 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 actions as expeditiously as practical. The EPA requests comment on whether the corrective actions to be triggered in case of an emissions performance deficiency should be adopted in rules and included in the original plan, or should be identified and adopted by the state after the deficiency is found.

The EPA also requests comment on the milestone approach and emission performance checks outlined above in the context of Option B and the planning approach for alternative state goals, which is described below.

e. Out-year requirements: Maintaining or improving the level of performance required by the final goal

The agency is determining state goals for affected EGU emission performance based on application of BSER during specified time periods. This raises the question of whether affected EGU emissions performance should only be maintained -- or instead should be further improved -- once the 2030-2032 goal is met. 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 intended the emission performance improvements required under CAA section 111(d) to be permanent. 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 beyond the proposed plan performance periods. The EPA requests comment on mechanisms for implementing this objective, including but not limited to the following options. The EPA also asks whether states should be allowed to choose from among the options below.

One implementation option would be to require the state plan to demonstrate that emission performance would continue to meet the plan period final goal on a three-year rolling average basis for up to 10 years (i.e., 2030-32 through 2039-41). This approach could be implemented through a second round of state plan analysis and submittals, perhaps in 2025, to make the demonstration and add any new measures if necessary. EPA requests comment on whether the performance period for the rolling average should be a period other than three years, and on whether a year later than the year 2025 would be preferable for a state plan to maintain emission performance after 2032.

The EPA also requests comment on a second “no backsliding” implementation option requiring continued implementation of plan measures for plans with EGU emission limits that ensure the full
level of performance required. The state could either continue
to implement those limits (no new submittal required) or
substitute other measures with equivalent effectiveness (new
submittal required to make this effectiveness demonstration).

The EPA further requests comment on how a “no backsliding”
concept could be implemented for end-use energy efficiency and
renewable energy programs and measures. For renewable energy
programs, the agency requests comment on requiring that the
renewable portfolio percentage level that was relied upon to
demonstrate achievement of the 2030-2032 performance level be
maintained. The EPA requests comment on what should be required
of end-use energy efficiency programs and measures that often
involve an annual percentage energy savings requirement or goal,
and require additional monetary expenditures each year to meet
those savings requirements or goals.

The EPA generally requests comment on appropriate
requirements to maintain the emission performance of affected
EGUs in years after 2032.

Alternatively, the EPA requests comment on whether the EPA
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, EPA
would apply its goal-setting methodology based on application of BSER in 2030 and beyond to a specified date. The agency requests comment on the appropriate final year for the EPA’s calculation of state goals that reflect application of BSER.

f. State flexibility to choose mass-based and rate-based goals after 2029

The EPA proposes that states have flexibility to choose between a rate-based and mass-based plan 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 the 2030-2032 performance period, 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 additional emissions headroom after 2029. The state either could adopt a rate-based performance level consistent with the final goal for specified time periods, or could adopt a new mass-based performance level that the state demonstrates will meet its translated, mass-based post-2029 goal for the relevant performance period.

g. 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 6. 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 5.

To accompany the alternative goals, the EPA requests comment on a matching option for state plan performance periods, Option C. This option would require state plans to show that the required emission performance level will be met on average by affected EGUs during the five-year 2020-2024 period. The required post-2024 level of emission performance would be initially demonstrated on a three-year average basis for 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 CO₂ emissions. This demonstration would be required as part of the same plan submittal that addresses 2020-2024 emission performance.

In connection with the alternative state goals, for the years after 2027, EPA requests comment on the same “out-year” issues and concepts for maintaining or improving emission performance over time that are described above (in subsection e). For the out-year concepts that involve additional state planning and demonstrations, EPA requests comment on whether
state plans due in 2016-2018, a second state plan due later, or other mechanisms that do not require a second plan submittal should provide for maintaining emission performance after 2027. In addition, the agency requests comment on the appropriate date for any second state plan submittals designed to maintain emission performance after the 2025-2027 performance level is achieved.

C. Criteria for Approving State Plans

The EPA is proposing to require the twelve plan components discussed elsewhere in this preamble. We will evaluate the sufficiency of each plan meeting those components based on four general criteria for a state plan to be approvable. First, a state plan must contain enforceable measures that reduce EGU CO₂ emissions. Second, these enforceable measures must be projected to achieve emission performance equivalent to the applicable state-specific CO₂ goal and derivative emission performance level in the emission guidelines, on a timeline equivalent to that in the emission guidelines. Third, EGU CO₂ 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

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138 Flexibilities provided to states in meeting this general approvability criterion are discussed below in Section VIII.B.2., emission performance.
entity), CO₂ emission performance outcomes, and implementation of corrective actions, if necessary. The EPA takes comments on all aspects of these general criteria and the ten specific plan components described below.

1. Enforceable measures

The first criterion in developing its plan, to ensure that the plan is enforceable and in conformance with the CAA, a state should follow established EPA guidance on enforceability.¹³⁹ This guidance serves as the foundation for the types of emission limits that 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 term as reasonable.

A state plan must include enforceable CO₂ emission limits (either rate-based or mass-based) that apply to affected EGUs. As noted above, the EPA is also proposing that a state plan may take a portfolio approach, which could include other enforceable

measures that, by facilitating reduced utilization of affected EGUs, would avoid EGU CO₂ emissions, and would be implemented by the state or by another party assigned responsibility by the state. As noted above, we are proposing that state plans need not be required to impose emission limits on affected EGUs that in themselves fully achieve the emission performance level, but we are seeking comment on whether state plans where emission limits applicable to affected EGUs alone would not assure full achievement of the required level of emission performance, should 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.¹⁴⁰

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 on all aspects associated with enforceability of a state plan and how to ensure compliance. We are also seeking comment on enforceability

¹⁴⁰ 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 indirect measures that avoid EGU CO₂ emissions, or emissions limits that apply to affected EGUs.
considerations under different state plan approaches, which is addressed below in VIII.E.

2. Emission performance

The second criterion for approvability is that the projected CO\textsubscript{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\textsubscript{2} emission performance level in the state plan. State plans that are projected to achieve an average CO\textsubscript{2} emission rate (expressed in, for example, lb CO\textsubscript{2}/MWh) or tonnage CO\textsubscript{2} emission outcome by all affected EGUs equal to, or lower than, the required level of CO\textsubscript{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.

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. They note that existing ISOS and RTOs 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 CO₂ 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.

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. At a minimum, the EPA proposes that all plans must specify how CO₂ emissions from affected EGUs are monitored and reported. The EPA is proposing that both mass-based and rate-based plans must include CO₂ 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 CO₂ 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.¹⁴¹

4. Reporting and corrective actions

The fourth criterion for approval is that a state plan (i) specify a process for periodic reporting to the EPA of overall plan performance and implementation (including compliance of affected entities with applicable standards of performance).

¹⁴¹ Considerations for quantification, monitoring, and verification of RE and demand-side EE measures are addressed in Section VII.E and in the State Plan Considerations TSD.
during the plan period, and (ii) include a process and schedule for modification 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 the multi-year plan period if emission performance is not met, or at specified interim stages within the multi-year plan period. For plans with self-correcting mechanisms, the agency is not proposing that requirements for modification be included in the plan. All of these considerations are addressed in more detail below in Section VIII.E.

The agency is also proposing that a state plan specify appropriate periodic reporting requirements for each affected entity in a state plan that should be reported at least annually, electronically, and disclosed on a state database accessible by the public and EPA. The EPA is requesting comment on the appropriate scope of these reporting requirements and

Comment [A225]: To what extent can existing reporting programs, e.g. the GHG Reporting Program, fulfill this requirement?

Comment [A226]: Does EPA envision receiving confidential business information as part of state submittals? If yes, please how EPA envisions handling sensitive information given that it wants to make the state plans public? Also see p. 275.
whether the reports should also be directly submitted by the affected 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, follow the EPA framework regulations at 40 C.F.R. 60.23–60.29, and include the following twelve components:

1. Identification of affected entities (affected EGUs and other responsible parties)

   The state plan must list the individual affected EGUs in the state that are subject to the plan and provide an inventory of CO₂ emissions from those units (for the most recent calendar year prior to plan submission for which data are available), and well as identify other parties in a state plan with responsibilities for implementation and enforcement of the plan.

2. Description of plan approach and geographic scope

   The state plan must describe its approach and geographic scope, including whether will achieve its required level of CO₂ 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 CO₂
emission goal identified for the state in the emission
guidelines or a translation of either 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 CO₂ per net MWh
of useful energy output or tons of CO₂ per year). As noted, in
the emission guidelines, EPA will establish the state goal in
the form of a CO₂ 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.

We are requesting comment on whether, to assist states that
seek to translate the rate-based goal into a mass-based limit,
the EPA should provide a presumptive translation of rate-based
to mass-based goal 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. This could include
information about acceptable analytical methods and tools, as

Comment [A227]: The offer to provide a
translation to mass-based for multi-state regions
should more clearly be extended to the second alternative.
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 will influence projections of CO₂ emissions by affected EGUs in any particular state. 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 Emission Performance: Mass-Based Goals and Plan Performance 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 the state’s emission performance level within the plan period. This demonstration will include a detailed description of the analytic process and tools used to project future CO₂ emission performance by affected entities under the plan and the results of the analysis.

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 is requesting comment on this suggestion.

5. Milestones
As described in greater detail in Section VIII.A.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 emissions 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 emissions performance improvement. As described in Section VIII.A.2.d., no less than every two years, beginning January 1, 2022, the state must compare emission performance achieved by affected EGU in the state versus 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 July 1 of the relevant year 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. Backstop measures

For a plan that does not include self-correcting mechanisms, the plan must also specify corrective measures that

Comment [A228]: Why single out an EGU’s emissions for the comparison to the state plan projections? Why not tier it, so if a state appears to be out compliance at the top level, then more information is needed to show that they will meet their target over the long term? Given that EPA has stated that trading programs could be included in SIPs, how would this requirement work?
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.

7. Identification of standards of performance and any other measures

A state plan must identify the affected entities to which each standard of performance 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 standard of performance 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 Standard, the EPA proposed that the appropriate standard of performance for new EGUs be no longer than 12 months (on average or cumulative calendar year basis). Similarly, the EPA proposes here that an appropriate averaging time for any standard of performance for existing affected EGUs and/or other affected entities subject to a state plan is no longer than 12 months (on average or cumulative) within the plan period. To maximize flexibility for the states, and in recognition that...
certain portfolio components may take longer to begin to achieve emission reductions than others, the EPA further proposes that such annual compliance timeframes may change over time (e.g., become more or less stringent in subsequent years), provided that the state plan demonstrates ultimate achievement of the state’s level of performance as described previously in this preamble.

8. Demonstration that each standard of performance is quantifiable, surplus, permanent, verifiable, and enforceable

In developing its CAA section 111(d) plan, to ensure that the plan is enforceable and in conformance with the CAA, a state should follow the EPA’s prior guidance on enforceability. This guidance serves as the foundation for the types of monitoring, reporting, and limits that 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 term as reasonable.

For each standard of performance, a plan must describe how it is quantifiable, surplus, permanent, verifiable, and enforceable with respect to an affected entity. A standard of performance is quantifiable if it can be reliably measured, using technically sound methods (i.e., scientifically based, peer-reviewed, and EPA-approved), in a manner that can be replicated. A standard of performance is surplus 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. This does not mean that measures in a standard of performance cannot also be used for other purposes. For example, if a state wished to take credit for CO₂ emissions avoided due to electric generation from a new wind farm, those emissions could be considered surplus for purposes of CAA section 111(d), even if generation from that wind farm was also being used to generate credits to comply with the state’s RPS requirements. Credit from avoided CO₂ emissions from that wind farm could not, however, be applied in more than one state’s CAA section 111(d) plan, except in the case of a multi-state plan where credit is assigned among states or emission performance is demonstrated jointly for all affected EGUs subject to the multi-state plan. The EPA solicits comment as to whether a reduction, not previously part of a plan,
becomes non-surplus (and therefore cannot be used for future crediting) if it is used as part of any state’s demonstration of compliance with its CAA section 111(d) plan.

A standard of performance is permanent if the standard of performance must be met by each applicable compliance year, or replaced by another standard of performance in a plan revision, or the state demonstrates in a plan revision that the emission reductions from the standard of performance are no longer necessary for the state to meet its emission performance level. A standard of performance is verifiable if adequate monitoring, recordkeeping and reporting are in place to enable the state and the Administrator to independently evaluate, measure, and verify compliance with it. A standard of performance 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 practicable enforceability (listed in Section VIII.C.1. of this preamble, and the Administrator and the state maintain the ability to enforce
against violations and secure appropriate corrective actions pursuant to Sections 113(a)–(h) of the Act.

9. Identification of monitoring, reporting, and recordkeeping requirements

The state plan must describe the CO₂ emission monitoring, reporting, and recordkeeping requirements for affected entities, 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 CO₂ 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.

We are also proposing monitoring and reporting protocols for net energy output under 40 CFR Part 75 that would allow the EPA’s existing Emission Collection and Monitoring Plan System (ECMPS) be used for purposes of meeting the net energy output reporting requirement. 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 times 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.) In addition, the protocol 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 plants; 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 Net Output Monitoring Issues Summary in the docket.) Also, consistent with the requests for comment in the proposed GHG NSPS regulations for new, 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.

A state plan that contains other standards of performance in addition to emission limits applicable to affected EGUs must include additional reporting and recordkeeping requirements related to these other measures. These 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.

The EPA is proposing to require state plans to include a record retention requirement of ten years and requests comment on this proposed timeframe. The EPA is also soliciting comment on whether these reports should be submitted electronically, to streamline transmission, and made publicly available.

10. Description of state reporting
A state plan must provide that the state will submit periodic 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 CO₂ 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 soliciting comment on whether these reports should be submitted electronically, to streamline transmission, and made publicly available.

11. Certification of state plan hearing

A state plan shall 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 framework regulations.

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 proposes to include in its plan as a federally enforceable standard of performance. 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 shall 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

Unless these emission guidelines specify otherwise, under the framework regulations state plans would be due nine months after finalization of the emission guidelines. 40 CFR
60.23(a)(1). 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. In response to these concerns, the EPA is proposing a plan submittal process with a submittal date of June 30, 2016 (one year after the expected finalization date of the emission guidelines) and that provides additional time to submit a complete plan to the EPA after June 30, 2016, when justified. This approach involves the option that we refer to as an initial submittal, followed by submittal of a complete state plan at a later date.

In addition, for states wishing to participate in a multi-state plan, the EPA is proposing that only one multi-state plan needs 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 EPA specifies otherwise. In view of the complexity of these plans, we are extending the submittal date. 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. If a state intends to make an initial submittal by June 30, 2016, in lieu of a complete plan, the state must notify EPA by letter of such intent by no later than April 1, 2016. In this letter, the state must adequately explain why more time is needed to submit a complete plan, outline the actions it is currently taking to develop a plan and commit to meet all of the requirements for an initial submittal by June 30, 2016. The EPA will respond to a state letter requesting an extension of the plan submittal date within 45 days through a formal letter response.

143 40 CFR 60.23(a)(1).
The EPA proposes that approvable justifications for seeking an extension 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 to limit the types of justifications that the EPA would consider for an extension.

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 emission guidelines, then the EPA will notify the state by letter, within 60 days, that it has received the initial state plan and that it appears to meet the minimum requirements. The letter will also specify the date by which the complete plan must be submitted to the EPA. The EPA believes this approach is authorized by, and consistent with, section 60.27(a) of the implementing regulations.

Where the EPA provides an extension of time to submit a complete plan, a state with a plan limited in geographic scope to the individual state would have until June 30, 2017, to submit a complete plan. If a state is developing a plan that
includes a regional or multi-state approach, it would have until
June 30, 2018, to submit a complete plan. Where the EPA approves
a state’s initial submittal, including a state’s justification
of the need for additional time to submit a complete plan after
June 30, 2016, the state would be required to provide one
update, on June 30, 2017, on its progress toward milestones and
schedules for developing and submitting a complete plan.144 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, the state must make an initial submittal by June
30, 2016. To be approved, the initial submittal must meet the
following proposed criteria: It must address all components of a
complete plan, including identifying which ones are not
complete. For incomplete components, the 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 reductions

144 This update would only apply to states that receive a two-
year extension for the submission of a complete plan, by June
30, 2018.
than other options. For the EPA to approve an extension of time for submittal of a complete plan, the initial submittal must include, among other elements, 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 CO₂ emissions (e.g., renewable energy 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.

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 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, then the EPA will notify the state by letter, within 60 days, that it has received the plan and that the initial state plan appears to meet the minimum requirements. The letter will also specify the date by which the complete plan must be submitted to the EPA.

States must submit complete plans to the EPA by the appropriate deadline, as identified in the preamble, and these range from June 30, 2016 to June 30, 2018. After receipt of a complete plan submittal, the EPA will review the plan and make a
determination, within six months, to approve or disapprove the plan through a notice-and-comment rulemaking process.

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 their plans, the state will need to make a number of decisions that will require careful consideration, in order to ensure that its plan both meets a state’s policy objectives and is approvable by EPA. In this section, we identify several key decision points and factors that states should consider when developing their plans.

The EPA has also drafted 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 (an entity that is regulated by the state, such as an electric distribution utility, or a private or public third-party entity), and the state itself. We are seeking comment on other appropriate examples of affected entities beyond the affected EGU.

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 the ability of a state to include requirements of standards of performance upon particular affected entities other than EGUS, and if so, which such entities, and what is the justification for the limitations.

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 CO₂-reducing programs. 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.

In considering options, the EPA recognized that the appropriate policy for determining treatment of existing state programs is related to the choice of methodology for setting state goals based on BSER. The EPA suggests that the treatment of existing state programs in state plan demonstrations should not conflict with the selected method for determining BSER-base state emissions performance goals. 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 CO₂ emission performance level by 2030.
As explained in Section VII above, the EPA’s proposed state-specific goals reflect many of the actions states have already taken to reduce or avoid EGU CO₂ emissions. CO₂ emission reductions due to shifts to lower CO₂-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.¹⁴⁵

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

¹⁴⁵ 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 CO₂ emission rate.
level of demand-side energy efficiency reflected in the state goals.

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, may qualify for use in showing 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.B) and relevant requirements for plan components in the emission guidelines (described above in Section VIII.C). Several options for treatment of existing 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 the plan period due to actions taken after the date of this

146 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 CO₂ emissions.
proposal. This proposed policy would recognize beneficial emission impacts from existing state programs and measures during the plan 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 emissions performance goals based on 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 also would ensure that any pre-2020 actions taken as a result of requirements in a state plan could be recognized as contributing toward meeting a state’s required emission performance level.

In general, the agency has identified two broad options for treatment of existing state programs and measures. As noted above, the EPA proposes emission reductions that existing state requirements, programs, or measures achieve during the plan period due to actions taken by a specified date. 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 plan period, the date of promulgation of emission guidelines, the end date of the base period for the EPA’s BSER-based goals analysis (e.g.,

**Comment [A232]**: Is this misworded? Above EPA says it will credit actions taken after the date or proposal, but here it seems to say by the date of proposal.
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 measures should be able to qualify for use during the plan period, considering the method used to set state goals. Whether this option is consistent in practice with the EPA’s application of 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 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 plan period are premised in part on a ramping up of end-use energy efficiency program and cumulative energy savings prior to the beginning of the plan 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 plan 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: Recognizing emission reductions that existing state requirements, programs, or measures achieved starting from a specified date prior to the plan period, as well as emission reductions achieved during the plan 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., 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.

The EPA requests comment on this option -- that emission reduction effects that occur prior to the beginning of the plan period could be applied toward meeting the required level of emission performance in a state plan. 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 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 BSER and its application in establishing state goals. In particular, we are seeking comment on whether 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 a state plan 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 RE and demand-side EE measures that, through MWh generation or MWh savings, avoid CO₂ emissions from affected EGUs. Measures installed after the eligibility date could generate MWh generation or MWh savings during the plan period, and related avoided CO₂ 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 renewable energy generating capacity installed in 2015 or later to meet an existing, on-the-books renewable portfolio standard would be a qualifying measure. However, only MWh generation beginning in 2020 and related avoided CO₂ emissions could be applied toward meeting a required emission rate 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, qualifying RE and demand-side EE measures after a respective eligibility date would not be included in the scenario that is used to project CO₂ emissions from affected EGUs when establishing a translated mass-based emission goal. This could be achieved by not including an end-use energy efficiency resource standard or renewable portfolio standard requirement in a reference case projection, beginning at a specified date. These considerations are addressed in more detail in Section VIII.E.7. below and in the Projecting Emissions Performance: Mass-Based Goals and Plan Performance TSD.

1. Incorporating RE and demand-side EE measures under a rate-based approach

Comment [A233]: This is confusing. Can EPA please explain – we have existing RE in 2012, RE constructed between 2012 and 2014, RE increases before some future year that are accumulated, then the increasing RE requirements from 2020 onward. How does the eligibility date change any of this when all the RE (existing, new) is ultimately included in the goal setting in EPA’s proposal?
We are proposing that RE and demand-side EE measures may be incorporated into a rate-based approach through an adjustment or tradable crediting system applied to an EGU’s reported CO\textsubscript{2} emission rate.\textsuperscript{147} Under such a process, measures that avoid CO\textsubscript{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\textsubscript{2} emission rate for EGU compliance purposes or used by the state to administratively adjust the average CO\textsubscript{2} emission rate of affected EGUs when demonstrating achievement of the required emission rate performance level in a state plan.

Under this approach, affected EGUs\textsuperscript{148} could comply with a CO\textsubscript{2} emission rate limit in part through the use of credits for actions that avoid CO\textsubscript{2} emissions from affected EGUs. If a state is implementing a portfolio approach, then the state could administratively adjust the average CO\textsubscript{2} emission rate of affected EGUs through a similar process, provided that the CO\textsubscript{2}-avoiding measures are enforceable elements of the state plan.

\textsuperscript{147} 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.

\textsuperscript{148} This could include an individual affected EGU or group of affected EGUs if a rate-based averaging or trading approach is used.
We are seeking comment on different approaches for providing such crediting or administrative adjustment of EGU CO\textsubscript{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\textsubscript{2} emissions. The approach chosen could have significant implications for the amount of adjustment or credit provided for RERE 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\textsubscript{2}/MWh emission rate. If adjustment or credits represent avoided CO\textsubscript{2} emissions, they would be subtracted from the numerator when determining an adjusted lb CO\textsubscript{2}/MWh emission rate.

A MWh crediting or adjustment approach implicitly assumes that the avoided CO\textsubscript{2} emissions come directly from the particular affected EGU (or group of EGUs) to which the credits are 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\textsubscript{2} emissions from that individual EGU or group of EGUs.\textsuperscript{149} In practice, the average or

\textsuperscript{149} As a result, the assumed avoided CO\textsubscript{2} emissions from an individual MWh of energy savings or MWh of generation from
marginal CO₂ emission rate in the power pool or identified region – representing the avoided CO₂ 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 CO₂ emissions derived by adjusting the MWh output of an affected EGU.

An alternative approach is to provide an adjustment based on the estimated CO₂ 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 CO₂ emissions come from the electric power pool or other identified region as a whole, rather than an individual EGU. The avoided CO₂ emissions are determined based on the MWh saved or generated, multiplied by a CO₂ emission rate for the power pool or region. This CO₂ emission rate could be based on the average or marginal emission rate in the power pool or region, or could be 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 CO₂ emissions avoided through RE and demand-side EE measures may be from non-affected renewable energy will differ based on the reported CO₂ emission rate of the individual EGU to which the MWh is applied as an adjustment to its MWh output.
EGUs, we are seeking comment on how this might be addressed in a state plan, whether when adjusting or crediting CO₂ 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 savings.

Utilities and states have conducted ongoing evaluation of end-use energy efficiency and renewable energy measures and programs for several decades. These evaluations, which include quantification, monitoring, and verification of results, generally rely upon a well-defined set of industry-standard practices and procedures. However, measurement approaches vary by state based on multiple factors, including the measure and program type being evaluated, the level and nature of regulatory oversight, the degree of state and utility experience with these
measures and programs, and the overall magnitude of program impacts.

Current state and utility quantification, monitoring, and verification approaches for RE and demand-side EE programs and mandates are discussed in the State Plan 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 are seeking comment on whether the EPA should establish good practice guidance for quantification, monitoring, and verification of RE and demand-side EE measures for an approvable state plan, and on the content of such guidance. We are also seeking comment on the appropriate basis for and resources used to establish such guidance, if the EPA were to take this approach. This includes consideration of existing state and utility protocols, as well as any international, national, and regional consensus standards or protocols.

In addition, we are seeking comment on whether any such guidance should identify types of end-use energy efficiency and renewable energy measures and programs for which quantification, monitoring, and verification of results is relatively straightforward and which are appropriate for inclusion in a
state plan. Such approaches might be subject to streamlined review of quantification, monitoring, and verification protocols included in an approvable 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 quantification, monitoring, and verification of measure and program outcomes. Other types of measures and programs, such as those that seek to alter consumer and building occupant behavior may 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 may have substantial impacts, but may require development of appropriate quantification, monitoring, and verification protocols.

5. Reporting and recordkeeping for responsible parties 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 end-use energy efficiency resource standard (EERS) or renewable portfolio standard (RPS). They may also include reporting by a vertically integrated utility implementing an approved integrated resource plan. In the latter instance, the utility may 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 emissions performance under the state plan. In other instances, a state agency or entity or a private or public third-party entity may be implementing programs and measures that support the deployment of 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 performance under the plan.

Examples of potential reporting obligations for responsible 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 recordkeeping and reporting requirements for affected entities beyond affected EGUs.

6. Treatment of interstate effects

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 measures allow for actions in neighboring states to meet the in-state requirement or explicitly address CO₂ 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 CO₂ emission requirements related to the generation of power purchased by regulated utilities, including power imported from out of state.

The agency recognizes the complexity of accounting for interstate effects associated with measures in a plan in a consistent manner, to minimize the likelihood of double counting. We also realize that interstate effects on CO₂ emissions from affected EGUs could be attributed in different manners in the context of an approvable state plan. The agency 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 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 used in determining BSER, a state could take into account in its plan only those CO₂ 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 states would have the flexibility to distribute the CO₂ emission reductions among states in the multi-state area, as long as the total CO₂ 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 CO₂ 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 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 on what such a demonstration should entail. We request comment on these and other approaches for taking into account CO₂ reductions from demand-side EE measures in state plans.

The EPA is also proposing that, for renewable energy measures, consistent with existing state RPS policies, a state could take into account all of the CO₂ emission reductions from renewable energy measures implemented by the state, whether they occur in the state and/or in other states. The EPA is also seeking comment on how to avoid double counting emission reductions using this proposed approach. The EPA is also proposing that states participating in multi-state plans could distribute the CO₂ emission reductions among states in the multi-state area, as long as the total CO₂ emission reductions claimed are equal to the total of each state’s in-state emission reductions for renewable energy measures. We also request comment on the option of allowing a state to take into account only those CO₂ emission reductions occurring in its state. We are also proposing that states could jointly demonstrate CO₂ 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 CO₂ emission reductions from renewable energy measures.

7. Projecting emission performance

As proposed, an approvable state plan will include a projection of CO₂ emissions performance by affected EGUs and other affected entities 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 also involve a projection of CO₂ emissions from affected EGUs during the plan period, 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 will need to include a
projection of CO2 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 CO2 emission rate achieved by affected EGUs or total CO2 emissions from affected EGUs.

The credibility of state plans under 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 and methods; and, how aspects of a plan are represented in these projections.

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. 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 emissions performance under different types of state plan approaches, are discussed in detail in the Projecting Emissions Performance: Mass-Based Goals and Plan Performance TSD.

We are seeking comment on the considerations discussed in this technical support document, 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 further seeking 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 provide technical resources for conducting projections.

The ISO/RTO Council, an organization of electric grid operators, has suggested that ISOs and RTOs could provide

\[150\] In many cases, this approach will also require the development of parameters for estimating the effect of individual state programs and measures, for use as input assumptions for modeling.
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 RTO or ISO 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 is requesting comment on this suggestion.**

8. 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 statutory provision that requires EPA regulations implementing section 111(d) to “permit 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.”
As the EPA recognized in 1975 when it adopted framework regulations for implementation of section 111(d) including the “useful life” statutory provision, application of these provisions may not be appropriate in every instance. For the reasons discussed below, 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 is unnecessary. The agency is requesting comment on its analysis below of the implications of EPA’s existing regulations interpreting “useful life” and “other factors” for purposes of this rulemaking. The agency also requests comment on whether it would be desirable to include any aspects of this analysis in regulatory text of this emission guideline.

The section addresses the legal background, implications for implementation of these emission guidelines, and lack of relevance to state emissions performance goals.

a. Legal background

As reflected in the framework regulations, the EPA believes that Congress included the remaining useful life provision in

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151 The agency is not reopening or considering changes to the existing framework regulations.
section 111(d) to avoid imposition of unreasonable costs on an existing source that has a limited remaining useful life. This could occur if a rule imposed high capital costs that would normally be amortized over long periods of time. If a facility will cease operation in the near future, it may have little time to earn revenue to help pay for the pollution control investment, and the facility’s retirement may occur before that debt is paid off. In addition, the impact of the controls in reducing emissions may be short-lived. As a result, it could be unreasonable for a facility with a short remaining useful life to incur the same pollution control costs that are reasonable for a facility with a long remaining useful life. Thus, remaining useful life could affect the determination of what requirements are appropriate for a facility with a short remaining useful life.

The EPA’s 1975 framework regulations contain the following provision, which addresses remaining useful life and other facility-specific factors that might affect requirements for an existing source under section 111(d):

"Unless otherwise specified in the applicable subpart, on a case-by-case basis for particular designated facilities, or classes of facilities, States may provide for the application of less stringent emission standards or longer compliance schedules than those otherwise required
by paragraph (c) of this section\textsuperscript{152}, provided that the state demonstrates with respect to each such 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 related to plant age” reflects 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 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 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

\textsuperscript{152} Paragraph (c) requires that for pollutants that endanger public health, standards of performance in state plans must be as stringent as EPA’s emission guidelines.
alter the extent to which states may authorize relaxations to standards of performance that would otherwise apply to a particular source or source category.

b. Implications for implementation of this emissions guideline

In general, the EPA notes that the framework 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. In the case of such emission guidelines, some individual sources, by virtue of their age or other unique circumstances, may warrant special accommodation. In the guidelines for affected EGUs that the EPA is proposing, the agency does not take that approach. Instead, the EPA is proposing to establish state emissions performance goals for the collective group of affected EGU in a state, and 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 section 111(d) plans to achieve those goals, no relief for individual facilities is needed from requirements in the EPA’s
guidelines, because the EPA’s guideline contains no emissions standards that the state must apply directly to a specific EGU. Rather, because of the flexibility for states to design their own standards, the states have the ability, and would be required, 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 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.

For these reasons, it appears that the quoted regulatory text above on remaining useful life and other factors need not apply to implementation of this proposed emission guideline. The agency requests comment on its interpretation.

c. Lack of relevance to state emissions performance goals and timing of achievement

The EPA also believes that remaining useful life and other facility-specific considerations should not affect the determination of a state’s rate-based or mass-based emissions performance goal or the state’s obligation to develop and submit an approvable section 111(d) plan that achieves that goal by the applicable deadline.

Comment [A239]: It seems to be implied, but EPA may want to consider directly stated that this flexibility to account for “remaining useful life” and “other factors” for individual facilities would not allow states to alter their overall state emission reduction targets.

Comment [A240]: For unforeseen closure of nuclear facilities, would EPA allow states to modify their state plans?
Under the proposed guideline, states would have the flexibility to adopt a state plan that relies on emissions-reducing requirements that do not require affected EGUs with a short remaining useful life to make major capital expenditures or incur unreasonable costs. Indeed, the EPA’s proposal would provide states with broad flexibility regarding ways to improve emissions performance through utilizing the emissions reduction methods represented by the four “building blocks.” 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. 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 EGU, the assumed 6 percent heat rate improvement in the EPA’s proposed BSER determination would be applicable to affected EGUs on a state-wide average basis, allowing the state to require a greater or lesser degree of heat rate improvement from any

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153 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.
individual EGU in light of that EGU’s remaining useful life or any other source-specific factors that the state deemed appropriate to consider. The agency 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. 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).

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 CO2 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

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154 Where states are unable to achieve the average 6 percent heat rate improvement assumed in the EPA’s BSER determination in light of the remaining useful life of one or more of their affected EGUs or for any other reasons (or where state so choose based on other considerations), they may adopt plan provisions that will obtain a lesser degree of average heat rate improvement from affected EGUs. A state is not required to achieve the same level of emission reductions with respect to any one building block as assumed in EPA’s BSER analysis, as long as they provide additional compensating emission reductions with respect to the other three building blocks.
therefore proposes that the remaining useful life of affected EGUs, and the other facility-specific factors identified in the existing framework 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.

G. Additional Factors That Can Help State Meet Their CO₂ 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, 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 CO2 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 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 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,”155 as well as the State Energy Efficiency Action Network’s “Energy Efficiency Program Impact Evaluation Guide.”156 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 this is available at [http://www2.epa.gov/carbon-pollution-standards/toolbox]. Current resources on the site focus on approaches states and other entities have already taken that reduce CO₂ emissions from the electric utility sector.

For the final rulemaking, the EPA plans to organize resources around the following two categories: state plan

155 http://epa.gov/airquality/eere/
156 http://www1.eere.energy.gov/seeaction/pdfs/emv_ee_program_impact_guide.pdf
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,\(^\text{157}\) National Action Plan for Energy Efficiency (NAPEE),\(^\text{158}\) 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 website 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.

\(^\text{157}\) Currently under development as a TSD

\(^\text{158}\) http://www.epa.gov/cleanenergy/energy-programs/suca/resources.html
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 (CO₂e), and it undergoes a change or change in the method of operation (modification) resulting in
an emissions increase of 75,000 tpy CO$_2$e 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 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, the EGU would trigger NSR.

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 change in 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). If we are satisfied with the state’s showing that the standards of performance in its plan, if complied with, will not have

Comment [A242]: This will need some explanation for audiences not steeped in the CAA.
emissions increase that trigger NSR, we will approve this provision in the state plan.

We request comment on whether, with adequate record support, the state plan could include a provision 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 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 CAA 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 section 111 standard to regulate GHGs (the EGU NSPS for new sources) and is not an issue for any other subsequent 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.

C. Interaction 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.\textsuperscript{159} 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 cancer and other serious health effects. The MATS rule will also reduce SO\textsubscript{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. Existing sources subject to the MATS rule are given until April 16, 2015 to comply with the rule's requirements; if an existing source is unable to comply by that deadline, a permitting authority has the ability to grant the source up to a one year extension, on a case-by-case basis, if such additional time is necessary for the installation of controls. [Text on December 2011 Enforcement]

\textsuperscript{159} 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.
Response Policy and/or progress in MATS implementation will be added.]

On [INSERT PUBLICATION DATE OF FINAL RULE (which should be finalized in April)], 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). This rule includes 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.160 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 control requirement that limits the number of fish destroyed through impingement, as well as site-specific entrainment mortality standards. Certain plants that withdraw very large volumes of water are also be required to conduct studies for use by the permit authority in determining the site-specific entrainment mortality standards for such facilities. The rule provides significant flexibility for compliance with the impingement standards, which are not projected to impose a

160 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.
substantial cost burden on affected facilities. With respect to entrainment, the rule calls upon the permitting authority to exercise best professional judgment in establishing appropriate site-specific standards, taking into account, among other factors, compliance costs, facility reliability and grid reliability. Existing sources subject to the 316(b) rule are given until [INSERT DATE] (i.e., 8 years from the rule's effective date) to comply with the rule's impingement standards. They must comply with applicable site-specific entrainment mortality standards 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 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 Clean Water Act. 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.161 While the agency is still 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 Steam Electric ELG proposal may 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, EPA’s current thinking is that, the revised risks, coupled with the ELG requirements

161 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).
that the agency may 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. 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.”

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 CO₂ 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.\(^{162}\)

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

\(^{162}\) 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.
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. 163 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. 164


164 [We could include some or all of the following modified language from proposed the SE ELG rule as a footnote:] 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 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.
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 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 SO2 standard. 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. The EPA has proposed the data requirements rule for the 1-hour SO2 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.

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165 The EPA has developed a comprehensive implementation strategy for these future actions that focuses resources on identifying and addressing unhealthy levels of SO2 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.
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 today’s 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

A. What are the air impacts?

The EPA anticipates significant emission reductions under the proposed guidance. CO₂ emissions are projected to be reduced, relative to the base case, by ___ percent in 2020 and ___ percent in 2030 under Option 1. Option 2 reflects reductions of ___ percent in 2020 and ___ percent in 2025. Tables 7 and 8 show expected climate and other air pollutants in the base case, with the proposed guidance and the anticipated net change between the base case and proposal emission levels in 2020 and 2030 for Option 1, and Tables 9 and 10 in 2020 and 2025 for Option 2, respectively.

Table 7 – Summary of Climate and Air Pollutant Emission Reductions with Proposed Option 1 - 2020

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<tr>
<th></th>
<th>CO₂ (million metric tonnes)</th>
<th>SO₂ (thousands of tons)</th>
<th>NOₓ (thousands of tons)</th>
<th>PM₂.₅ (thousands of tons)</th>
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<td>Proposed Guidance</td>
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166 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 8 - Summary of Climate and Air Pollutant Emission Reductions with Proposed Option 1 - 2030

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<th>CO₂ (million metric tonnes)</th>
<th>SO₂ (thousands of tons)</th>
<th>NOₓ (thousands of tons)</th>
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Table 9 - Summary of Climate and Air Pollutant Emission Reductions with Alternative Option 2 - 2020

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<th></th>
<th>CO₂ (million metric tonnes)</th>
<th>SO₂ (thousands of tons)</th>
<th>NOₓ (thousands of tons)</th>
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Table 10 - Summary of Climate and Air Pollutant Emission Reductions with Alternative Option 2 - 2025

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<th></th>
<th>CO₂ (million metric tonnes)</th>
<th>SO₂ (thousands of tons)</th>
<th>NOₓ (thousands of tons)</th>
<th>PM₂.₅ (thousands of tons)</th>
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The reductions in these tables do not account for reductions in HAPs that may occur as a result of this rule. For instance, the fine particulate reductions presented above only partly reflect reductions in many heavy metal particulates.

**B. What are the energy impacts?**
The proposed guidelines have important energy market implications. Under Option 1, average nationwide retail electricity prices are projected to _____ in the contiguous U.S. by ___ percent in 2030. While consumers average monthly electricity bills are anticipated to decline by ___ percent in 2030.

The average delivered coal price to the power sector is projected to _____ by ___ percent in 2020 and ___ percent in 2030, relative to the base case with Option 1. The EPA also projects that electric power sector-delivered natural gas prices will _____ by ___ percent in 2020 and ______ by ___ percent in 2030. Natural gas use for electricity generation will _____ by ___ billion cubic feet (BCF) in 2020 relative to the base case. Finally, the EPA projects coal production for use by the power sector, a large component of total coal production, will ______ by ___ million tons in 2020 from base case levels, which is about ___ percent of total coal produced for the electric power sector in that year in the base case.

Under the proposed Option 1, the EPA projects ___ GW of coal-fired generation may be uneconomic to maintain and may be removed from operation by 2030. This level of projected, currently unplanned coal retirements exceeds the base case projection by ___ GW. If current forecasts of either natural gas
prices or electricity demand are revised in the future to be higher, there would be greater incentive to keep these coal-fired units operational. Energy impacts of the proposed guidelines are discussed more extensively in the RIA that is in the docket for this action.

C. 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 policy case 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.

The EPA projects that the annual incremental compliance cost of Option 1 is estimated to be $___ billion in 2020 and $___ billion (2011$) in 2030, excluding the costs associated with monitoring, reporting, and recordkeeping (MRR). The incremental compliance cost of Option 2 is estimated to be $___ billion in 2020. In 2025, the estimated compliance cost of Option 2 is estimated to be $ ___ billion (with the assumed
levels of end-use energy efficiency). These important dynamics are discussed in more detail in the RIA. 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 $____ million (2011$) in 2020 for Option 1. More detailed cost estimates are available in the RIA included in the docket.

D. 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. Natural gas prices are projected to ______ by roughly ___ percent in 2020 in Option 1 and by ___ percent under Option 2 in 2020, on an average nationwide basis. Under Option 1, natural gas prices ____ by percent in 2030. Coal prices are projected to _____ by roughly ____ percent in 2020 under both Options, on a nationwide average basis. Retail electricity prices are projected to _____ by percent under Option 1 and _____ by ____ percent under Option 2,
both in 2020 and on an average nationwide basis. By 2030 under Option 1, electricity prices _____ by ___ percent. Coal retirements are projected to be ___ W for Option 1 in 2030 and ___ GW under Option 2 in 2025.

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 a ___ reduction on overall electricity demand levels in 2030 for Option 1, and a ___ 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 changes in price, changes in quantity produced, and changes in profitability of firms affected. 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 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, 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. As such, given the wide range of approaches that may be used, quantifying the associated employment impacts is difficult. EPA’s employment analysis includes projected employment impacts associated 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 XXXXXX to XXXXXX job-years in 2020. Demand side energy efficiency employment impacts may range from approximately YYYYY to YYYYY job-years in 2020.

E. What are the benefits of the proposed goals?

Implementing the proposed standards will generate benefits by reducing emissions of CO₂ as well as criteria pollutants and their precursors, including SO₂, NOx and directly emitted particles. SO₂ and NOx are precursors to PM₂.₅ (particles smaller than 2.5 microns), and NOx is a precursor to ozone. 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 CO₂ and the health co-benefits associated with reduced exposure to PM₂.₅ and ozone. In summary, we estimate the total combined climate benefits and health co-benefits for Option 1 to be $__ billion to $__ billion in 2020 and $__ billion to $__ 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 $__ billion to $__ billion in 2020 and $__ billion to $__ 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 11 and 12 of this preamble.
Table 11. Summary of the Monetized Global Climate Benefits for the Proposed Standards (billions of 2011 dollars)\(^a\)

<table>
<thead>
<tr>
<th>CO₂ Emission Reductions (metric tons)</th>
<th>Discount Rate (Statistic)</th>
<th>Monetized Climate Benefits</th>
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<tr>
<td>Option 1 in 2020</td>
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<td>5 percent (average SCC)</td>
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<td>3 percent (average SCC)</td>
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<td>2.5 percent (average SCC)</td>
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<td>3 percent (95(^{th}) percentile SCC)</td>
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<td>Option 1 in 2030</td>
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<td>5 percent (average SCC)</td>
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<td>3 percent (95(^{th}) percentile SCC)</td>
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<td>Option 2 in 2020</td>
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<td>5 percent (average SCC)</td>
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<td>3 percent (95(^{th}) percentile SCC)</td>
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<td>Option 2 in 2025</td>
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<td>3 percent (95(^{th}) percentile SCC)</td>
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\(^a\) Climate benefit estimates reflect impacts from CO₂ emission changes in the analysis years presented in the table and do not account for changes in non-CO₂ GHG emissions. These estimates are based on the federal government’s global SCC estimates for the analysis years (2020, 2025, 2030) and are rounded to two significant figures.
Table 12. Summary of the Monetized Health Co-Benefits for the Proposed Standards in the U.S. (billions of 2011 dollars)\textsuperscript{a}

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>National Emission Reductions (short tons)</th>
<th>Monetized Health Co-benefits (3 percent discount)</th>
<th>Monetized Health Co-benefits (7 percent discount)</th>
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<tbody>
<tr>
<td><strong>Option 1 in 2020</strong></td>
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<tr>
<td>PM\textsubscript{2.5} precursors \textsuperscript{b}</td>
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<td>SO\textsubscript{2}</td>
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<td>Directly emitted PM\textsubscript{2.5} (Elemental Carbon and Organic Carbon)</td>
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<td>Directly emitted PM\textsubscript{2.5} (crustal)</td>
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<td>NO\textsubscript{x}</td>
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<td>Ozone precursor \textsuperscript{c}</td>
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<td>NO\textsubscript{x}</td>
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<td>Total Monetized Health Co-benefits</td>
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<td>Total Monetized Health Co-benefits combined with Monetized Climate Benefits \textsuperscript{d}</td>
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<td><strong>Option 1 in 2030</strong></td>
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<td>PM\textsubscript{2.5} precursors \textsuperscript{b}</td>
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<td>Total Monetized Health Co-benefits combined with Monetized Climate Benefits \textsuperscript{d}</td>
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<td><strong>Option 2 in 2020</strong></td>
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<td>PM$_{2.5}$ precursors $^b$</td>
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<td>Directly emitted PM$_{2.5}$ (Elemental Carbon and Organic Carbon)</td>
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</tbody>
</table>

Total Monetized Health Co-benefits

Total Monetized Health Co-benefits combined with Monetized Climate Benefits $^d$

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Option 2 in 2025

PM$_{2.5}$ precursors $^b$

<table>
<thead>
<tr>
<th>PM$_{2.5}$ precursors $^b$</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>SO$_2$</td>
<td></td>
</tr>
<tr>
<td>Directly emitted PM$_{2.5}$ (Elemental Carbon and Organic Carbon)</td>
<td></td>
</tr>
<tr>
<td>Directly emitted PM$_{2.5}$ (crustal)</td>
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<tr>
<td>NO$^x$</td>
<td></td>
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<tr>
<td>Ozone precursor $^c$</td>
<td></td>
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<tr>
<td>NO$^x$</td>
<td></td>
</tr>
</tbody>
</table>

Total Monetized Health Co-benefits

Total Monetized Health Co-benefits combined with Monetized Climate Benefits $^d$

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* [Emission reductions of directly emitted particles are not yet available but will be added to the totals above.] 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; 95$^{th}$ 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 U.S. government’s SCC estimates to analyze CO$_2$ climate impacts of this rulemaking. The U.S. government first published the federal SCC estimates in 2010 following an interagency process that included the EPA and other executive branch entities; the process used three integrated assessment models 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.\footnote{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>.
\footnote{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 the Council of Economic Advisers, Council on Environmental Quality, Department of Agriculture, Department of Commerce, Department of Energy, Department of Transportation, Environmental Protection...
EPA and other agencies have sought public comments on the USG 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 CO₂ emissions in the year 2020 (2011 dollars).¹⁶⁹ 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.

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 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 because of a lack of precise information on the nature of damages and because 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 CO₂ emission reductions to inform the benefit-cost analysis. The new versions of the models used to estimate the values presented below offer some improvements in these areas, although further work is warranted. Accordingly, the EPA and other parties continue to conduct research on

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Comment [A248]: The implication is that the models are inadequate but this is not necessarily the case – it will just depend on the degree of “lag” and the direction of the “most recent research.” Please modify language to be more specific.
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. Because we were unable to conduct air quality modeling for this rule, we instead 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 associated with that change in air quality, which are then divided by the emissions in specific sectors. National average benefit-per-ton estimates for the EGU sector were derived using the approach published in Fann et al. (2012), but they have since been updated to reflect the studies and population data in the 2012

Comment [A249]: Given the magnitude of these co-benefits relative to CO2 benefits EPA needs to do air quality modelling on the model scenarios for the final rule.

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PM NAAQS RIA and were separated into regional estimates to provide greater spatial resolution. 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. 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.


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 effects 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 function 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\textsuperscript{175} and the extended Six Cities cohort study.\textsuperscript{176} We present the PM\textsubscript{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\textsubscript{2.5} co-benefits estimates derived from expert judgments (Roman et al., 2008)\textsuperscript{177} as a characterization of uncertainty regarding the PM\textsubscript{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)\textsuperscript{178} and the upper end based on a function from Levy, et al.


(2005)\textsuperscript{179}. Similar to PM\textsubscript{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 \textit{Integrated Science Assessment for Particulate Matter},\textsuperscript{180} which evaluated the substantial body of published scientific literature, reflecting thousands of epidemiology, toxicology, and clinical studies that documents the association between elevated PM\textsubscript{2.5} 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\textsubscript{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 due to time and resource limitations, 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/m$^3$). Using the Lepeule, et al. (2012) study, 67 percent of the population is exposed above the LML of 8 µg/m$^3$. 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

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Comment [A250]: Suggest rethinking the presentation of this justification – is it only resource limits or was the complexity of understanding state responses an equal or greater contributor? If it was only resource limitations, perhaps a slightly more detailed explanation could be given?

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181 In addition, site-specific emission reductions will depend upon how states implement the guidelines.
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 SO₂, NOₓ, 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 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 scenarios of implementing the proposed guidelines. This proposal sets goals to reduce CO₂ emissions from the electric power industry. Actions taken to comply with the proposed guidelines will also reduce the emissions of directly emitted PM₂.₅, sulfur dioxide (SO₂) and nitrogen oxides (NOₓ). The benefits associated with these PM, SO₂ and NOₓ reductions are referred to as co-benefits, as these reductions are not the primary objective of this rule.

The EPA has used the U.S. government’s social cost of carbon (USG SCC) estimates — i.e., the monetary value of impacts associated with a marginal change in CO₂ emissions in a given year, to analyze CO₂ climate impacts of this rulemaking. The four USG 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 by the USG: the model average at 3% discount rate. The EPA estimates that in 2020 this Option 1 proposal will yield monetized climate benefits (in 2011$) of approximately $__ billion (3 percent model average). The air pollution health co-benefits in 2020 are estimated to be $__ billion to $__ billion (2011$) for a 3 percent discount rate and $__ billion to $__ billion (2011$) 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 $__ billion (2011$) in 2020 [MRR costs to be added when available]. The quantified net benefits (the difference between monetized benefits and costs) in 2020 are estimated to be $__ billion to $__ billion (2011$) using a 3 percent discount rate (model average).

For Option 1 in 2030, the EPA estimates this proposal will yield monetized climate benefits (in 2011$) of approximately $__ billion (3 percent, model average). The air pollution health co-benefits in 2030 are estimated to be $__ billion to $__ billion (2011$) for a 3 percent discount rate and $__ billion to $__ billion (2011$) 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 $__ billion (2011$) in 2030. The quantified net benefits (the difference between monetized benefits and costs) in 2030 are estimated to be $__ billion to $__ billion (2011$) using a 3 percent discount rate (model average). Based upon the foregoing discussion, it remains clear that the benefits of the proposal Option 1 are substantial in 2020 and 2030 and far exceed the costs.

**TABLE 13—SUMMARY OF THE MONETIZED BENEFITS, COMPLIANCE COSTS, AND NET BENEFITS FOR THE FINAL RULE – OPTION 1 IN 2020**

<table>
<thead>
<tr>
<th>[Billions of 2011$]</th>
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<tbody>
<tr>
<td>3% Discount rate</td>
</tr>
<tr>
<td>Climate benefits b</td>
</tr>
<tr>
<td>Air pollution health co-benefits c</td>
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<tr>
<td>Total Compliance Costs d</td>
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<tr>
<td>Net Monetized Benefits e</td>
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<td>Non-monetized Benefits</td>
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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 CO₂ emission changes and does not account for changes in non-CO₂ GHG emissions. Also, different discount rates are applied to SCC than to the other estimates because CO₂ emissions are long-lived and subsequent damages occur over many years. The benefit estimates in this table are based on the average SCC estimated by the USG 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 USG 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 PM₂.₅ and ozone associated with emission reductions of directly emitted PM₂.₅, SO₂ and NOₓ. 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 PM₂.₅ 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%. 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>
<thead>
<tr>
<th>TABLE 14—SUMMARY OF THE MONETIZED BENEFITS, COMPLIANCE COSTS, AND NET BENEFITS FOR THE FINAL RULE – OPTION 1 IN 2030ᵃ</th>
</tr>
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<tbody>
<tr>
<td>[Billions of 2011$]</td>
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<tr>
<td>3% Discount rate</td>
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<tr>
<td>Climate benefits ᵇ</td>
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<td>Air pollution health</td>
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<td>co-benefits c</td>
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<td>----------------</td>
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<tr>
<td>Net Monetized Benefits e</td>
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<tr>
<td>Direct exposure to SO2 and NO2</td>
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<tr>
<td>Ecosystem Effects</td>
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<tr>
<td>Visibility impairment</td>
</tr>
</tbody>
</table>

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 CO2 emission changes and does not account for changes in non-CO2 GHG emissions. Also, different discount rates are applied to SCC than to the other estimates because CO2 emissions are long-lived and subsequent damages occur over many years. The benefit estimates in this table are based on the average SCC estimated by the USG 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 USG 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 PM2.5 and ozone associated with emission reductions of directly emitted PM2.5, SO2 and NOx. 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 PM2.5 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%. This estimate includes monitoring, recordkeeping, and reporting costs and demand side energy efficiency program and participant costs. 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 are shown in Tables 15 and 16. As these tables reflect, net benefits in 2020 are estimated to be $__ to $__ billion assuming a 3 percent discount rate and from $__ to $__ billion assuming a discount rate of 7 percent. In 2025, net benefits are estimated to be $___ billion to $__ billion (3 percent discount rate) and from $__ billion to $__ billion (7 percent discount rate).

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-CO₂ greenhouse gases and co-benefits from reducing exposure to SO₂, NOx, and hazardous air pollutants (e.g., mercury and hydrogen chloride), as well as ecosystem effects and visibility impairment.

TABLE 15 - SUMMARY OF THE MONETIZED BENEFITS, COMPLIANCE COSTS, AND NET BENEFITS FOR THE FINAL RULE - OPTION 2 IN 2020[^3]

[^3]: [Billions of 2011]
All estimates are for 2020, and are rounded to two significant figures, so figures may not sum.  

The climate benefit estimate in this summary table reflects global impacts from CO₂ emission changes and does not account for changes in non-CO₂ GHG emissions. Also, different discount rates are applied to SCC than to the other estimates because CO₂ emissions are long-lived and subsequent damages occur over many years. The benefit estimates in this table are based on the average SCC estimated by the USG 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 USG 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.

The air pollution health co-benefits reflect reduced exposure to PM₂.₅ and ozone associated with emission reductions of directly emitted PM₂.₅, SO₂ and NOₓ. 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 PM₂.₅ and ozone. These models assume that all fine particles,

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<tr>
<th></th>
<th>3% Discount rate</th>
<th>7% Discount rate</th>
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<tr>
<td>Climate benefits †</td>
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<td></td>
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<tr>
<td>Air pollution health</td>
<td></td>
<td></td>
</tr>
<tr>
<td>co-benefits ‡</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total Compliance Costs †</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Net Monetized Benefits ‡</td>
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<td></td>
</tr>
<tr>
<td>Non-monetized Benefits</td>
<td>Direct exposure to SO₂ and NO₂</td>
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<td></td>
<td>___ tons of Hg and ___ tons of HCl</td>
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<td></td>
<td>Ecosystem Effects</td>
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<tr>
<td></td>
<td>Visibility impairment</td>
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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%. This estimate includes monitoring, recordkeeping [MRR to be added when available], and reporting costs and demand side energy efficiency program and participant costs.

a 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 16 — SUMMARY OF THE MONETIZED BENEFITS, COMPLIANCE COSTS, AND NET BENEFITS FOR THE FINAL RULE – OPTION 2 IN 2025a

[Billions of 2011]

<table>
<thead>
<tr>
<th></th>
<th>3% Discount rate</th>
<th>7% Discount rate</th>
</tr>
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<tbody>
<tr>
<td>Climate benefits b</td>
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<td></td>
</tr>
<tr>
<td>Air pollution health co-benefits c</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total Compliance Costs d</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Net Monetized Benefits e</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Non-monetized Benefits</td>
<td>Direct exposure to SO₂ and NO₂ ___ tons of Hg and ___ tons of HCl Ecosystem Effects Visibility impairment</td>
<td></td>
</tr>
</tbody>
</table>
All estimates are for 2025, and are rounded to two significant figures, so figures may not sum.

The climate benefit estimate in this summary table reflects global impacts from CO₂ emission changes and does not account for changes in non-CO₂ GHG emissions. Also, different discount rates are applied to SCC than to the other estimates because CO₂ emissions are long-lived and subsequent damages occur over many years. The benefit estimates in this table are based on the average SCC estimated by the USG 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 USG 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.

The air pollution health co-benefits reflect reduced exposure to PM₂.₅ and ozone associated with emission reductions of directly emitted PM₂.₅, SO₂ and NOₓ. 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 PM₂.₅ 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.

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%. This estimate includes monitoring, recordkeeping [MRR to be added when available], and reporting costs and demand side energy efficiency program and participant costs.

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.

### 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 [insert #].

The information collection requirements are based on the recordkeeping and reporting burden associated with developing, implementing, and enforcing a state plan to limit CO₂ 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 66,618 hours at a total annual labor cost of $4,481,958. The total annual burden for the federal government (averaged over the first 3 years following promulgation of this proposed action) is estimated to be 23,377 hours at a total annual labor cost of $1,201,952.

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 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 [INSERT DATE OF PUBLICATION IN THE FEDERAL REGISTER], a comment to OMB is best assured of having its full effect if OMB receives it by [INSERT DATE 30 DAYS AFTER PUBLICATION IN THE FEDERAL REGISTER]. The final rule will respond to any OMB or public comments on the information collection requirements contained in this proposal.

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 17 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 17. Potentially Regulated Categories and Entities

<table>
<thead>
<tr>
<th>Category</th>
<th>NAICS Code</th>
<th>Examples of Potentially Regulated Entities</th>
</tr>
</thead>
<tbody>
<tr>
<td>Industry</td>
<td>221112</td>
<td>Fossil fuel electric power generating units.</td>
</tr>
<tr>
<td>State/Local Government</td>
<td>221112b</td>
<td>Fossil fuel electric power generating units owned by municipalities.</td>
</tr>
</tbody>
</table>

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 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) national standards for allowable concentrations of particulate matter in ambient air as required by section 109 of the CAA. See also American Trucking Associations v. EPA, 175 F.3d at 1044-45 (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, emission guidelines established under CAA section 111(d) do not impose any direct compliance requirements on regulated entities. Thus, this proposed rule is not subject to the requirements of section 202 or section 205 of UMRA.
This proposed rule is also not subject to the requirements of section 203 of UMRA because it contains no regulatory requirements that might significantly or uniquely affect small governments.

In light of the interest among governmental entities, the EPA initiated consultations with governmental entities while formulating the provisions of the proposed standards for 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

This proposed action does not have federalism implications. It would not have substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government, as specified in EO 13132. This proposed action would not impose substantial direct compliance costs on state or local governments, nor would it preempt state law. Specifically, emission guidelines established under CAA section 111(d) do not impose any direct compliance costs on regulated entities. Thus, Executive Order 13132 does not apply to this action.

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 on their lands.
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 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, but provides guidance to any tribe with delegated authority to address CO₂ 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. For this proposed action for existing EGUs, a tribe that has one or more affected EGUs on its lands\textsuperscript{182} would have the opportunity, but not the obligation, to establish a CO\textsubscript{2} performance standard and a plan for its tribal lands.

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, 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

\textsuperscript{182} The EPA is aware of at least three affected sources located in Indian Country, two on [Navajo] lands -- the Navajo Generating Station and the Four Corners Generating Station -- and one on [Ute] lands -- the Bonanza Generating Station.
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 CO₂ reductions resulting from implementation of the proposed guidelines 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 adverse 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 ___ percent price increase for retail electricity prices nationwide in 2020 and a ___ percent reduction in coal-fired power production as a result of this rule. The EPA
projects that electric power sector delivered natural gas prices
will increase by about ___ percent in 2020. For more
information on the estimated energy effects, please refer to the
economic impact analysis for this final rule. 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 NTTAA of 1995 (Public Law No. 104-113; 15 U.S.C. 272 note) directs the EPA to use Voluntary Census Standards in their regulatory and procurement activities unless to do so would be inconsistent with applicable law or 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 the 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). 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 limits GHG emissions by establishing CO₂ emission guidelines for existing fossil fuel-fired EGUs. In addition to reducing CO₂ emissions, implementing the proposed rule would reduce other emissions from EGUs which are dispatched less under a state’s 111(d) program because of their relatively low energy efficiency. These emission reductions will include SO₂ and NOₓ, which form ambient PM₂.₅ and ozone in the atmosphere, and hazardous air pollutants (HAP), such as mercury. In the final rule revising the annual PM₂.₅ standard¹⁸⁴, 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.\textsuperscript{185} Therefore, in areas where this rulemaking reduces exposure to PM$_{2.5}$, ozone and methylmercury persons with low socioeconomic status would also benefit. The regulatory impact analysis (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 methylmercury, there may also be EGUs whose emissions of one or more of these pollutants increase as a result of the proposed emission guidelines for existing fossil fuel-fired EGUs. 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 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 of GHGs and/or other regulated pollutants. As we noted in the

NSR discussion in this preamble, a state can take steps to avoid increased utilization of particular EGUs and thus to 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 CO₂ emission guidelines for existing fossil fuel-fired EGUs would be 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 CO₂ emission guidelines for existing fossil fuel-fired EGUs can be expected to cause more such changes. Increased utilization generally would not cause high concentrations around such EGUs than is already occurring, but may make periods of relatively high concentration more frequent. It should be noted that the gas-fired sources that are likely to be dispatched more frequently than at present have very low emissions of particulate matter, SO₂ and hazardous air pollutants per unit of electrical output, such that local (or regional) air quality for these pollutants is likely to be affected very little. Many are also very well controlled for emission of NOx. Depending on the specificity of the state 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 NO₂ concentrations in the design of the 111(d) program, or separately from the 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 will result in regional and national pollutant reductions; however, there likely will 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.

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 pollutant 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:

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:

1. Section 60.27 is amended by revising paragraph (b) to read as follows:

   (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.

2. Part 60 is amended by adding subpart UUUUU to read as follows:


   Sec. 60.5700 What is the purpose of this subpart?
   60.5705 What greenhouse gases are regulated by this subpart?
   60.5710 Am I affected by this subpart?
   60.5715 What is the review and approval process for my state plan?
   60.5720 What if my state plan is not approvable?
   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?
   60.5730 Is there an approval process for a negative declaration letter?
60.5735 What authorities will not be delegated to state, local, or tribal agencies?

State Plan

60.5740 What must I include in my state plan?
60.5745 Can I work with other states to develop a multi-state plan?
60.5750 Can I include existing requirements, programs, and measures in my state plan?
60.5755 What are the timing requirements for submitting my state plan?
60.5760 What must I include in an initial submittal in lieu of a complete state plan?
60.5765 What are the state rate-based CO₂ emissions performance goals?
60.5770 What is the procedure for converting my state rate-based CO₂ emissions performance goal to a mass-based CO₂ emissions performance goal?
60.5775 What schedules, performance periods, and compliance periods must I include in my state plan?
60.5780 What emissions standards and enforcing measures must I include in my plan?
60.5785 What is the procedure for revising my state plan?

Applicability of State Plans to Affected EGUs

60.5790 Does this subpart directly affect EGU owners and operators in my state?
60.5795 What affected EGUs must I address in my state plan?
60.5800 What affected EGUs are exempt from my state plan?
60.5805 What applicable monitoring, recordkeeping, and reporting requirements do I need to include in my state plan for affected EGUs?

Recordkeeping and Reporting Requirements

60.5810 What are my state recordkeeping requirements?
60.5815 What are my state reporting requirements?

Definitions

60.5820 What definitions apply to this subpart?

Introduction

§ 60.5700 What is the purpose of this subpart?

This subpart establishes emission guidelines and compliance schedules for 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 subpart A of this part, the requirements of this subpart will apply.

§ 60.5705 What greenhouse gases are regulated by this subpart?

The greenhouse gas regulated by this subpart is carbon dioxide (CO₂).

§ 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 [INSERT DATE OF PUBLICATION IN THE FEDERAL REGISTER], you must submit a state plan to 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 [INSERT DATE OF PUBLICATION IN THE FEDERAL REGISTER] 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 paragraph §60.27(b) the Administrator will have six 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 in lieu of a complete state plan the Administrator will have six months after the date required for submission to approve or disapprove the request.

§ 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 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 options for a state to meet its section 111(d) obligations?

No.
§ 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, 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 [INSERT DATE OF PUBLICATION IN THE FEDERAL REGISTER] 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 paragraphs (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.

State Plan

§ 60.5740 What must I include in my state plan?

(a) You must include the elements described in paragraphs (a)(1) through (a)(10) of this section in your state plan.
(1) Identification of affected entities, including an inventory of CO₂ 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 emissions performance level for affected entities that will be achieved through implementation of the plan, during the plan performance period.

   (i) The identified emissions performance level must be equivalent to or better than the levels of the rate-based CO₂ emissions performance goal in Table 1 of this Subpart for affected entities in your state. The emissions performance levels may be in either a rate-based form or a mass based form which is calculated according to § 60.5770. The CO₂ emissions performance level specified must include either of the following as applicable:

   (a) For a rate-based CO₂ emissions performance level, the identified level must represent the CO₂ emissions rate, in pounds of CO₂ per MWh of net energy output that will be achieved by affected entities, on average, during the plan performance period, including identification of any increments of
performance that will be achieved within the plan performance period.

(b) For a mass-based \( \text{CO}_2 \) emissions performance level, the identified level of performance must represent the total tons of \( \text{CO}_2 \) that will be emitted by affected entities during the plan performance period, including identification of any increments of performance that will be achieved within the plan performance period.

(4) A demonstration that the plan is projected to achieve the state’s emissions performance levels for affected entities according to § 60.5740(a)(3).

(5) Identification of emissions standards for each affected entity, compliance period for each emissions standard, and demonstration that the emissions standards are, when taken together, sufficiently protective to meet the state emissions performance level.

(6) A demonstration that each emissions standard is quantifiable, surplus, permanent, verifiable, and enforceable with respect to an affected entity.

(7) 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.
(8) Description of the process, contents, and schedule for annual state reporting to the EPA about plan implementation and progress including information required under § 60.5820.

(9) 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.

(10) 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);

(iii) Materials supporting the projected mass-based emissions performance goal, calculated pursuant to § 60.5770, if applicable; and

(iiii) Materials necessary to support evaluation of the plan by 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?
plan?

(a) 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). States may submit a multi-state plan that:

(b) Demonstrates CO₂ emission performance jointly for all affected entities in all states participating in the multi-state plan, as follows:

(i) For states demonstrating performance based on CO₂ 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 CO₂/MWh emission rate to be achieved by all affected EGUs in the multi-state area during the plan performance period; or

(ii) For states demonstrating performance based on mass CO₂ emissions, the level of performance identified in the multi-state plan pursuant to 60.5740(a)(3) will be total CO₂ emissions by all affected EGUs in the multi-state area during the plan performance period.

(c) Assigns 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)-(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:

(i) 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 [INSERT DATE OF PUBLICATION IN THE FEDERAL REGISTER]; and

(ii) 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).

(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 emissions performance that will be achieved by affected EGUs under the complete plan;

(3) A commitment by the state to maintain existing state programs and measures that limit or avoid CO₂ emissions from affected EGUs, 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 emissions 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
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.

§ 60.5765 What are the state rate-based CO₂ emissions performance goals?

(a) The annual average state rate-based CO₂ emissions performance goals for the plan performance periods of 2020 through 2029, and in 2030 and thereafter are respectively listed in Table 1 of this Subpart. The state rate-based CO₂ emissions performance goal may be converted to a mass-based emissions performance goal according to § 60.5770.

§ 60.5770 What is the procedure for converting my state rate-based CO₂ emissions performance goal to a mass-based CO₂ 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 CO₂ 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:
(b) 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)(10).

(c) 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)(10).

(d) The conversion must represent the tons of CO₂ 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 CO₂/MWh rate equal to the rate-based goal for the state identified in Table 1 of this Subpart.

§ 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 for each affected entity regulated under the plan.

(c) Your state plan must show that it will achieve the state emissions performance level by end of the performance period and as well as at increments of performance within the performance period. Additionally you must include provisions to demonstrate progress toward the state emissions performance level in a state’s annual report.

§ 60.5780 What emissions standards and enforcing measures must I
include in my plan?

(a) Your state plan shall include emissions standard(s) that are quantifiable, verifiable, surplus, permanent, and enforceable with respect to each affected entity. The plan shall include the methods by which each emissions standard meets each of the following requirements in paragraphs (b)-(f).

(b) An emissions standard is quantifiable with respect to an affected entity if it can be reliably measured, in a manner that can be replicated.

(c) An emissions 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 emissions standard.

(d) An emissions standard is surplus with respect to an affected entity if it is not already incorporated as an emissions standard in another state plan unless incorporated in multi-state plan.

(e) An emissions standard is permanent with respect to an affected entity if the emissions standard must be met for each compliance period, or unless it is replaced by another emissions standard in an approved plan revision, or the state demonstrates in an approved plan revision that the emissions reductions from the emission standard are no longer necessary for the state to
(f) An emissions 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) – (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 emissions 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 emissions 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 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, 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 [DATE OF PROPOSED RULE PUBLICATION IN THE FEDERAL REGISTER] reaches compliance with all the provisions of this subpart.

§ 60.5795 What affected EGUs must I address in my state plan?

The EGUs that must be addressed by your state plan are any affected steam generating unit, IGCC, or stationary combustion turbine that commences construction before [DATE OF PROPOSED RULE PUBLICATION IN THE FEDERAL REGISTER]

§ 60.5800 What affected EGUs are exempt from my state plan?

Affected EGUs that are exempt from your state plan include 1) those that are subject to subpart TTTT as a result of commencing construction after the subpart TTTT applicability date and 2) those subject to subpart TTTT as a result of commencing modification or reconstruction prior to the submittal of the 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).

(1) If an affected EGU is required to meet a rate based emissions 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 CO2 mass emissions from each affected unit using the procedures in paragraphs (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 CO2 continuous emissions monitoring system (CEMS) to directly measure and record CO2 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 CO2 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 CO2 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 CO₂ 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 CO₂ mass emissions by using Equation G-4 in Appendix G to part 75 of this chapter according to the requirements in paragraphs (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 (Fₑ) using Equation F-7b in section 3.3.6 of appendix F to part 75 of this chapter, and may use these Fₑ values in the emissions calculations instead of using the default Fₑ 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. 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 CO₂ 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 CO₂ 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 CO₂ 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 to the delegated authority all hourly CO₂ 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 each 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 emissions performance goals.
(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 CO₂ 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 a report no later than 60 days after completing each annual performance period as defined in your state plan regarding 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 CO₂ emissions rate or total mass
CO₂ 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.

(2) A list of affected entities and their compliance status
with the applicable emissions standards specified in the state
plan.

(3) A list of all affected EGUs and their reported CO₂
emissions performance for each compliance period during the
reporting period, and prior reporting periods.

(3) All other required information, as specified in your
state plan according to §60.5740(a)(8).

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 of this part) and B.

Affected electric generating unit or Affected EGU means a
steam generating unit, an IGCC facility, or a stationary
combustion turbine that serves a generator capable of selling
greater than 25 MW to a power distribution system.

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).

CO₂ emissions performance goal means the rate-based CO₂ 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 use a steam-generating unit or stationary combustion turbine to simultaneously produce both electric (or mechanical) and useful thermal energy 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.

Distillate oil means fuel oils that contain no more than 0.05 weight percent nitrogen and comply with the specifications for fuel oil numbers 1 and 2, as defined by the American Society of Testing and Materials in ASTM D396 (incorporated by reference, see § 60.17); diesel fuel oil numbers 1 and 2, as defined by the American Society for Testing and Materials in ASTM D975 (incorporated by reference, see § 60.17); kerosene, as defined by the American Society of Testing and Materials in ASTM D3699 (incorporated by reference, see § 60.17); biodiesel as defined by the American Society of Testing and Materials in ASTM D6751 (incorporated by reference, see § 60.17); or biodiesel
blends as defined by the American Society of Testing and Materials in ASTM D7467 (incorporated by reference, see § 60.17).

_Emission performance level_ in a state plan means the level of emissions performance for affected entities specified in a state plan, according to § 60.5745.

_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 CO₂ 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 CO₂ 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 has a base load rating heat input of greater than 73 MW (250 MMBtu/h), that supplies 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 and 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 energy, 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). Measurements must be performed using 0.2 accuracy class electricity metering instrumentation and calibration procedures as specified under ANSI Standards No. C12.20.

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 ISO 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 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 ISO 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).

Oil means crude oil or petroleum or a fuel derived from crude oil or petroleum, including distillate and residual oil, and gases derived from solid oil-derived fuels (not meeting the definition of natural gas).

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

Stationary combustion turbine means all equipment, including but not limited to the turbine engine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), heat recovery system, fuel compressor, heater, and/or pump, post-combustion 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) that has a base load rating heat input of greater than 73 MW (250 MMBtu/h) and that supplies 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 plus any integrated equipment that provides electricity or useful thermal output to the affected facility or auxiliary equipment.

Thermal output for this subpart means the energy in recovered thermal output measured against the energy in the thermal output at ISO conditions.
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., thermal energy used to reduce fuel moisture is considered useful thermal output).