AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

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

DATES: Comments on the proposed rule. 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]. Comments on the information collection request. Under the
Paperwork Reduction Act (PRA), since the Office of Management and Budget (OMB) is required to make a decision concerning the information collection request between 30 and 60 days after [INSERT 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 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/.

ADDRESS: 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.

Facsimile: Fax your comments to (202) 566-9744, Attn:
Docket ID No. EPA-HQ-OAR-2013-0602.

Mail: Send your comments to the EPA Docket Center, U.S.

**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](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/tnn/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:

<table>
<thead>
<tr>
<th>Acronym</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>ACEEE</td>
<td>American Council for an Energy Efficient Economy</td>
</tr>
<tr>
<td>AEO</td>
<td>Annual Energy Outlook</td>
</tr>
<tr>
<td>AFL-CIO</td>
<td>American Federation of Labor and Congress of Industrial Organizations</td>
</tr>
<tr>
<td>ASTM</td>
<td>American Society for Testing of Materials</td>
</tr>
<tr>
<td>BSER</td>
<td>Best System of Emission Reduction</td>
</tr>
<tr>
<td>Btu/kWh</td>
<td>British Thermal Units per Kilowatt-hour</td>
</tr>
<tr>
<td>CAA</td>
<td>Clean Air Act</td>
</tr>
</tbody>
</table>
CBI Confidential Business Information  
CCS Carbon Capture and Storage (or Sequestration)  
CEMS Continuous Emissions Monitoring System  
CHP Combined Heat and Power  
CO₂ Carbon Dioxide  
DOE Department of Energy  
ECMPS Emissions Collection and Monitoring Plan System  
EERS Energy Efficiency Resource Standard  
EGU Electric Generating Unit  
EIA Energy Information Administration  
EM&V Evaluation, Measurement and Verification  
EO Executive Order  
EPA Environmental Protection Agency  
FR Federal Register  
GHG Greenhouse Gas  
GW Gigawatt  
HAP Hazardous Air Pollutant  
HRSG Heat Recovery Steam Generator  
IGCC Integrated Gasification Combined Cycle  
IPCC Intergovernmental Panel on Climate Change  
IPM Integrated Planning Model  
IRP Integrated Resource Plan  
ISO Independent System Operator  
kw Kilowatt  
kWh Kilowatt-hour  
lb CO₂/MWh Pounds of CO₂ per Megawatt-hour  
LBNL Lawrence Berkeley National Laboratory  
MMBtu Million British Thermal Units  
MW Megawatt  
MWh Megawatt-hour  
NAAQS National Ambient Air Quality Standards  
NAICS North American Industry Classification System  
NAS National Academy of Sciences  
NGCC Natural Gas Combined Cycle  
NOx Nitrogen Oxides  
NRC National Research Council  
NSPS New Source Performance Standard  
NSR New Source Review  
NTTAA National Technology Transfer and Advancement Act  
NYSERDA New York State Energy Research and Development Authority  
OMB Office of Management and Budget  
PM Particulate Matter  
PM₂·₅ Fine Particulate Matter  
PRA Paperwork Reduction Act
Organization of This Document. The information presented in this preamble is organized as follows:

I. General Information
   A. Executive Summary
   B. Organization and Approach for this Proposed Rule

II. Background
   A. Climate Change Impacts from GHG Emissions
   B. GHG Emissions from Fossil Fuel-fired EGUs
   C. The Utility Power Sector
   D. Statutory and Regulatory Requirements

III. Stakeholder Outreach and Conclusions
   A. Stakeholder Outreach
   B. Key Messages from Stakeholders
   C. Key Stakeholder Proposals
   D. Consideration of the Existing Range of Policies and Programs
   E. Conclusions

IV. Rule Requirements and Legal Basis
   A. Summary of Rule Requirements
   B. Summary of Legal Basis

V. Authority to Regulate Carbon Dioxide and EGUs, Affected Sources, and Treatment of Categories
VI. Building Blocks for Setting State Goals and Considerations
A. Introduction
B. Building Blocks for Setting State Goals
C. Detailed Discussion of Building Blocks and Other Options Considered
D. Potential Combinations of the Building Blocks as Components of the Best System of Emission Reduction
E. Determination of the Best System of Emission Reduction

VII. State Goals
A. Overview
B. Form of Goals
C. Proposed Goals and Computation Procedure
D. State Flexibilities
E. Alternate Goals and Other Approaches Considered
F. Reliable Affordable Electricity

VIII. State Plans
A. Approach
B. Criteria for Approving State Plans
C. State Plan Components
D. Process for State Plan Submittal and Review
E. State Plan Considerations
F. Additional Factors That Can Help States Meet Their CO₂ Emission Performance Goals
G. Resources for States to Consider in Developing Plans

IX. Implications for Other EPA Programs and Rules
A. Implications for NSR Program
B. Implications for Title V Program
C. Interactions with Other EPA Rules

X. Impacts of the Proposed Action
A. What are the air impacts?
B. Comparison of Building Block Approaches
C. Endangered Species Act
D. What are the energy impacts?
E. What are the compliance costs?
F. What are the economic and employment impacts?
G. What are the benefits of the proposed goals?

XI. Statutory and Executive Order Reviews
A. Executive Order 12866, Regulatory Planning and Review, and Executive Order 13563, Improving Regulation and Regulatory Review
B. Paperwork Reduction Act
C. Regulatory Flexibility Act
D. Unfunded Mandates Reform Act of 1995
E. Executive Order 13132, Federalism
F. Executive Order 13175, Consultation and Coordination With Indian Tribal Governments
G. Executive Order 13045, Protection of Children From Environmental Health Risks and Safety Risks
H. Executive Order 13211, Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use
I. National Technology Transfer and Advancement Act
J. Executive Order 12898, Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations

XII. Statutory Authority

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). In this summary, we broadly outline the proposal; discuss its purpose; summarize its major provisions, including its approach to determining goals; describe flexibilities available to states, including timing requirements both for states to submit plans and for EGUs to meet obligations under those plans; and briefly describe the estimated CO₂ emission reductions, costs and benefits expected to result from full implementation of the proposal.
This rule, as proposed, would continue progress already underway to lower the carbon intensity of power generation in the United States. The proposal incorporates critical elements that reflect the information and views shared during the unprecedented effort that the EPA has undertaken, beginning in the summer of 2013, to interact directly with and solicit input from a wide range of states and stakeholders. This effort encompassed several hundred meetings across the country with state environmental and energy officials, public utility commissioners, system operators, utilities and public interest advocates, as well as members of the public. A great many participants submitted written material and data to the EPA as well.

Nationwide, by 2030, this rule would achieve CO₂ emission reductions from the power sector of approximately 30 percent from CO₂ emissions levels in 2005. This goal is within reach because innovations in the production, distribution and use of electricity are already making the power sector more efficient and sustainable while maintaining a diverse energy mix. This proposed rule would reinforce and continue this progress. The EPA projects that, in 2030, this rule will lead to meaningful reductions in harmful carbon pollution resulting in net climate and health benefits of $47 billion to $78 billion. At the same
Time coal and natural gas will remain the two dominant sources of electricity generation in the U.S. with each providing more than 30 percent of the projected generation.

The proposed guidelines also reinforce the steps already being taken by states and utilities to upgrade aging electricity infrastructure with 21st century technologies and ensure that these trends continue in ways that are consistent with the long-term planning and investment processes already used in this sector. The proposal provides flexibility for states to build upon their progress in addressing GHGs and allows them to pursue policies to reduce carbon pollution that: 1) continue to rely on a diverse set of energy resources, 2) ensure electric reliability, 3) provide affordable electricity and, 4) recognize investments that states and power companies are already making.

The proposal has two main elements: 1) state-specific goals for reductions from power plants and 2) guidelines for the elements needed for a state plans to be approved when they are submitted to the EPA for review as required under section 111(d). To set the state-specific goals, the EPA analyzed the practical and affordable strategies that states and utilities are already using to lower carbon pollution from the power sector. These strategies include improvements in efficiency at carbon-intensive power
plants, programs that enhance the dispatch priority of low-emitting and renewable power sources, and programs that help homes and businesses use electricity more efficiently.

While this proposal lays out state-specific goals, it does not prescribe how a state should meet those goals. The Clean Air Act and EPA’s implementing regulation authorize the EPA to set these goals, and rely on states to take the lead on meeting them by creating a plan that is consistent with the EPA’s guidelines. This approach ensures that each state will have the flexibility to design a program to meet its goal in ways that reflect its particular circumstances and policy objectives. Each state can do so alone or can collaborate with other states on multi-state or regional plans that may provide additional opportunities for cost savings and flexibility.

To facilitate the state planning process, this proposal lays out the components of a state plan to meet the goal, the latitude states have in developing compliance strategies, the flexibility they have in the timing for submittal of their plans and the flexibility states have in determining the schedule by which their sources must achieve the reductions required under state plans. 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 and electricity demand) also differ. Therefore, the proposed guidelines provide states with options for meeting the state-specific goals established by the EPA in a flexible manner that accommodates a diverse range of state approaches. This proposal also gives states considerable flexibility with respect to the timeframes for plan development and implementation, providing up to two or three years for submission of final plans after the proposed emission rate guidelines are finalized and providing up to fifteen years for full implementation of all emission reduction measures.

The EPA believes that this proposal, which employs the flexibilities inherent in CAA section 111(d), will provide states with ample opportunity to design plans that use innovative, cost-effective regulatory strategies and that take advantage of the investments already being made in programs and measures that lower the carbon intensity of the power sector and thus reduce GHG emissions that cause harmful climate change.
a. Policy context and industry conditions

This proposal is an important step toward achieving the emissions reductions needed to address the serious threat of climate change. GHG pollution threatens the health and welfare of the American public by leading to potentially rapid and 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 over 77 percent of U.S. GHG emissions.

The President’s Climate Action Plan,¹ issued in June 2013, recognizes that climate change comes with far-reaching harmful consequences and real economic costs. The Climate Action Plan details a broad array of actions to reduce GHG emissions that contribute to climate change and affect public health and the environment. One of the plan’s goals is to reduce CO₂ emissions from power plants. This is because 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. “To accomplish this goal, President Obama issued a Presidential Memorandum² directing

the EPA to complete carbon pollution standards, regulations or
guidelines, as appropriate, for new, modified, reconstructed and
existing power plants, and to build on state leadership to move
toward a cleaner power sector.

Advancements in innovative power sector technologies, in
the availability and cost of low carbon fuel, and in energy
efficient demand-side technologies, as well as economic
conditions, are already changing the way power is produced,
distributed and used. In addition, the average age of the coal-
fired generating fleet is increasing. In 2025, the average age
of the coal-fired generating fleet is projected to be 49 years
old, and 20 percent of units would be more than 60 years old if
they remained in operation at that time. Therefore, even in the
absence of additional environmental regulation, states and
utilities can be expected to be, and already are, making plans
to address the changes necessitated by the aging of current
assets and infrastructure. With change inevitably under way
between now and 2030, a CAA section 111(d) rulemaking for CO2
emissions can inform current and ongoing decision making by
states and utilities while prompting states to develop and

2 Presidential Memorandum – Power Sector Carbon Pollution
office/2013/06/25/presidential-memorandum-power-sector-carbon-
pollution-standards
implement plans that will reduce GHG emissions and lower the carbon intensity of the power sector, while ensuring a reliable supply of power at a reasonable cost. The proposed guidelines are designed to build on and reinforce progress by states and companies on a growing variety of sustainable strategies to reduce power sector CO\textsubscript{2} emissions. At the same time, the EPA believes that this proposal provides flexibility for states to develop plans that can be crafted for their individual and unique circumstances and that can be aligned with their other environmental policy and energy and economic goals. All states will have the flexibility to shape compliance plans as they believe appropriate for meeting the proposed CO\textsubscript{2} reduction goals.

This includes states such as Kentucky, West Virginia and Wyoming, with long-established reliance on coal-fired generation, as well as states such as Washington and Oregon with a commitment to promoting renewable energy (including through sustainable forestry initiatives). It also includes states that are already participating in or implementing CO\textsubscript{2} reduction programs, such as the Regional Greenhouse Gas Initiative (RGGI), California’s AB 32, and Colorado’s “Clean Air, Clean Jobs Act”.

To make plans to reduce CO\textsubscript{2}, states can rely on and extend programs they may already have created to address the power sector. Those states committed to Integrated Resource Planning
(IRP) would be able to establish their CO₂ reduction plans within that framework. Similarly, states with a more deregulated power sector system can develop CO₂ reduction plans within that framework. At the same time, states would also be able to address the economic interests of their utilities and ratepayers by using the flexibilities in this proposed action: 1) to reduce costs and minimize stranded assets, and 2) to work with other states on multi-state approaches that reflect the regional structure of electricity operating systems that exists in most parts of the country and is critical to ensuring a reliable supply of affordable energy. The proposed rule provides a broad range of compliance options for a wide and diverse range of companies that own and operate fossil fuel-fired EGUs, including vertically integrated companies in regulated markets, independent power producers, rural cooperatives and municipally-owned utilities. The proposal would also allow states to work together with individual companies on potential specific challenges. These and other flexibilities are discussed further in Section VIII of the preamble.

b. CAA section 111(d) requirements

Under CAA section 111(d), state plans must establish standards of performance that reflect the degree of emission

¹ See also 40 CFR 60.22(b)(5).
limitation achievable through the application of the “best system of emission reduction, 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).” Consistent with CAA section 111(d), the EPA is proposing state-specific goals that reflect the EPA’s calculation of the emission reductions that the states can achieve through the application of BSER.

This calculation reflects the degree of emission limitation that the state plan must achieve in order to implement the BSER that the EPA has determined has been adequately demonstrated and that, in turn, would be required to be, and via the calculation, has been, applied to the affected EGUs in each state. A CAA section 111(d) state plan will differ from a state implementation plan (SIP) for a criteria air pollutant national ambient air quality standard (NAAQS) in several respects.

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.
reflecting the significant differences between CAA sections 110 and 111. A CAA section 110 SIP must be designed to meet a specific ambient air quality level -- the NAAQS for the criteria air pollutant -- for a particular area (not for a source category) within a timeframe specified in the CAA, and the NAAQS, in turn, is based on the current body of scientific evidence and, by law, does not reflect consideration of cost. A CAA section 111(d) state plan must be designed to meet a level specific to emissions from a particular source category within a timeframe determined by the Administrator and, to some extent, by each state. Moreover, the emission levels for the source category reflect a determination of BSER, which incorporates consideration of cost, technical feasibility and other factors.

To determine BSER for reducing CO₂ emissions at affected EGUs, the EPA considered numerous measures that are already being implemented, and can be implemented more broadly, to improve emission rates and to reduce overall CO₂ emissions from fossil fuel-fired EGUs. These measures fall into four main categories or “building blocks.” Overall, the BSER proposed here is based on a range of measures that comprise improved operations at EGUs, dispatching lower-emitting EGUs and zero-emitting energy sources, and end use energy efficiency, all of which have been amply demonstrated via their current widespread...
use by utilities and states. The proposed guidelines are structured so that states would not be required to use each and every one of the measures that the EPA determines constitute BSER or to apply any one of those measures to the same extent that the EPA determines is achievable and cost-effective with respect to that measure. Instead, in developing its plan, each state will have the flexibility to select the measure or combination of measures it prefers in order to achieve its CO₂ emission reduction goal. Thus, a state could choose to achieve more reductions from one measure encompassed by BSER and less from another, or it could choose to include measures that were not part of the EPA’s BSER determination, as long as the state achieves the CO₂ reductions necessary to meet its goal. As explained in further detail in Sections VI, VII and VIII of this preamble regarding the agency’s determination of BSER, the EPA is offering the opportunity via this proposal to comment on the key assumptions, the methodology, and the specific data used to calculate the state-specific CO₂ goals, and on the broad flexibilities provided to meet the goals and ensure states the necessary tools to address any distinctive circumstances (such as the remaining useful life of certain EGUs) without adjusting the underlying targets.
This proposed rule sets forth the state goals that reflect BSER and guidelines for states to use in developing their plans to reduce CO₂ from fossil fuel-fired EGUs. The preamble describes the proposed expectations for state plans and discusses options that the EPA has considered. It also explains the EPA’s authority to define BSER, as well as state goals and the states’ responsibility to develop and implement standards of performance consistent with BSER. 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 extensive input from states and a wide range of stakeholders that the EPA sought and has received since the summer of 2013. The EPA invites 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 that have been in place since Congress first enacted the CAA in 1970 and that have been implemented pursuant to regulations promulgated in 1975 and followed in previous CAA section 111(d) rulemakings since then. These provisions ensure that, in concert with the provisions of CAA
sections 110 and 112, new and existing major stationary sources address significant air pollutants that are harmful to public health and the environment. These requirements call on the EPA to develop emission guidelines, which reflect EPA’s determination of BSER, for states to follow in formulating compliance plans to implement standards of performance to achieve emissions reductions consistent with BSER. 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 EGUs in the power sector.

The CAA, as interpreted by the courts, identifies several factors for the EPA to consider in a BSER determination: 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 measures that reduce CO₂ emissions from existing fossil fuel-fired EGUs either by reducing the CO₂ emission rate at those units or by reducing...
the units’ CO₂ emission total by shifting generation from higher-emitting fossil fuel-fired EGUs to lower- or zero-emitting options (including both low- or zero-emitting generation and demand-side energy efficiency). As the EPA has done in making BSER determinations in the past, the agency considered the types of strategies that states and operators are already employing to reduce the covered pollutant (in this case, CO₂) from affected sources (in this case, fossil fuel-fired EGUs). For this pollutant and source category, many states and companies are already taking action to reduce GHGs. For example, currently 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. Many individual companies also have significant voluntary GHG emission reduction programs. Such strategies and the proposed BSER determination reflect the fact that, in almost all states, the production, distribution and use of electricity are undertaken in ways that accommodate reductions in both pollution emissions rates and total emissions. Specifically, electricity production, at least to some extent, takes place interchangeably between and among multiple generation facilities and different types of generation, a fact that Congress, the EPA and the states have long since relied on in enacting or promulgating
programs, such as Title IV of the CAA, the NOx SIP call, the Cross State Air Pollution Rule (CSAPR) and RGGI.

As a result, the agency, in quantifying state goals, assessed what combination of electricity production or energy demand reduction across generation facilities can offer the most cost-effective approach to achieving CO₂ emission reductions. States, in turn, will be able to look broadly at opportunities across their electricity system in devising plans to meet their goals. Importantly, states may rely on measures that they already have in place, including renewable energy standards and demand-side energy efficiency programs, and the proposal details how such existing state programs can be incorporated into state plans.

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 reduce or limit mass CO₂ emissions from fossil fuel-fired EGUs. These measures encompass two basic approaches: 1) reducing the carbon intensity of certain affected EGUs by improving the efficiency of their operations, and 2) addressing affected EGUs’ mass emissions by varying their utilization levels. For purposes of expressing BSER as an
emissions limitation, in this case in the form of state-level goals, we propose to group these measures into four main categories, or “building blocks”. These building blocks can also be used as a guide to states for constructing broad-based, cost-effective, long-term strategies to reduce CO\(_2\) emissions. The EPA believes that the application of measures from each of the building blocks can achieve CO\(_2\) emission reductions at fossil fuel-fired EGUs such that, when combined with measures from other building blocks, the measures represent the “best system of emission reduction ... adequately demonstrated” for fossil fuel-fired EGUs. The building blocks are:

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

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

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

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

The four building blocks are described in detail in Sections VI and VII of this preamble. As those sections explain, while the EPA found that each of the building blocks met the attributes of BSER, combining all four blocks best represents BSER because it achieves greater emission reductions, is more cost effective and takes better advantage of the wide range of measures already in use at the state and company level to reduce CO₂ from EGUs. Those sections also explain how the EPA considered more aggressive application of measures in each block. This includes consideration of options in some blocks that the EPA determined not to represent BSER for existing sources (such as the inclusion of retrofit carbon capture and storage or sequestration (CCS) on existing units), as well as consideration of more aggressive application of measures that the EPA determined do represent a component of BSER (such as more aggressive application of demand-side
measures). While the EPA made these determinations by applying the BSER factors to each measure, the EPA also considered the impacts of combining each of the measures into a unified BSER.

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

In sum, 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 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
believe 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, actions and
measures that companies and states are already undertaking
to reduce GHG emissions and with current trends in the
electric power sector, driven by efforts to reduce GHGs, as
well as by other factors, such as advancements in
technology. Reliance on all four building blocks in this
way also supports the goals of achieving meaningful, and
technically feasible reductions of CO₂ at a reasonable cost,
while also promoting technology and approaches that are
important for achieving further reductions, all while
providing the states with a balance of flexibility and
direction. Finally, the EPA believes that the inherent
flexibility of the measures encompassed in the four
building blocks reinforces the inherent flexibility of the
current electricity system operations and the system’s
capacity to deliver affordable and reliable electricity
because these measures rely on the flexibility of the electricity system itself.

In addition to proposing the four building blocks as the basis for BSER, the EPA is also soliciting comment on application of only the first two building blocks as BSER, while noting that application of only the first two building blocks achieves fewer CO₂ reductions at a higher cost.

The EPA recognizes that states differ in important ways, including in their mix of existing EGUs and in the policy priorities that they are pursuing. Consequently, opportunities and preferences for reducing emissions, as reflected in each of the building blocks, vary across states. While the state-specific goals that the EPA is proposing in this rule are based on consistent application of a goal setting methodology across all states, they are designed to account for these key differences. The state-specific CO₂ reduction requirements and CO₂ rate-based goals derived from application of the methodology vary because, in setting the goals for a state, the EPA used data specific to each state’s EGUs and certain other attributes of its electricity system (e.g., current mix of generation resources).
This approach and incorporation of the measures in each of the building blocks reflect information provided and priorities expressed during the EPA’s recent, extensive public outreach process. These ranged from the states’ desires for flexibility and recognition of varying state circumstances to the success that states and companies have had in adopting a range of pollution- and demand-reduction strategies. The state-specific approach embodied in both CAA section 111(d) and this proposal recognizes that ultimately states are the most knowledgeable about their specific circumstances and are best positioned to evaluate and leverage existing and new generation capacity and programs to reduce 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 or strategies that are not explicitly mentioned in any of the four building blocks and may use those technologies or strategies as part of their overall plan. Further, this approach allows regional compliance strategies. The agency also recognizes the important functional relationship between the period of time over which measures are deployed
and the stringency of emission limitations those measures can achieve. Because, for its primary proposal, the EPA is proposing a 10-year period over which to achieve the full required CO₂ reductions, a period that begins more than five years from the date of this proposal, a state could take advantage of this relationship in the design of its program by using relevant combinations of building blocks to achieve its state goal in a 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. 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 adjusted state-average emission rates from affected EGUs that could be achieved at reasonable cost by 2030 through implementation of the four building blocks described above. The proposed interim goals would apply over a 2020-2029 phase-in period. The proposed final goals reflect the EPA’s quantifications of cost-effectively achieved cumulatively or on average over the respective plan period to achieve reductions in overall CO₂ emissions at affected EGUs. State-specific goals are intended to demonstrate
phase-in period. They reflect the level of reductions in CO₂ emissions and emission rates and the extent of the application of the building blocks that would be presumptively approvable in a state plan during the ramp-up to achieving the final goal.

The EPA is proposing to allow each state flexibility with regard to the form of the goal. 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 compliance timing, to the state-specific rate-based goal set by the EPA.

We believe that this approach to establishing requirements for states in developing their plans responds both to the needs of an effectively implemented program and to the range of viewpoints expressed by stakeholders regarding the simultaneous need for both flexibility and clear guidance on what would constitute an approvable state plan. We likewise believe that this approach represents a reasonable balance between two competing objectives grounded in CAA section 111(d) — a need for rigor and
consistency in calculating emission reductions and a need for flexibility in establishing and implementing the standards of performance that reflect those emission reductions. The importance of this balance is heightened by the fact that the operations of the electricity system itself rely on the flexibility made available and achieved through dispatching between and among multiple interconnected EGU’s, demand management and end use energy efficiency. We view the proposed goals as providing this rigor where required by the statute with respect to the amount of emissions reductions, while providing states with flexibility where permitted by the statute, particularly with respect to the development and implementation of performance standards and the overall compliance plans.

This approach recognizes that state plans for emission reductions can, and must, be consistent with a vibrant and growing economy and supply of reliable, affordable electricity to support that economy. It further reflects the growing trend, as exemplified by many state and local clean energy policies and programs, to shift energy production away from carbon-intensive fuels to a more sustainable system that puts greater reliance on renewable energy, and energy efficiency.
c. State plans

i. Approach

Each state will determine, and include in its plan, emissions performance levels for its affected EGUs that are equivalent to the state-specific CO₂ goal in the emission guidelines, as well as the measures needed to achieve those levels and the overall goal. As part of determining this level, the state will decide whether it will adopt the rate-based form of the goal established by the EPA or translate the rate-based goal to a mass-based goal. The state must then establish a standard, or set of standards, of performance, as well as implementing and enforcing measures, to achieve the emission performance level specified in the state plan. The state may choose the measures it will include in its plan to achieve its goal. The state may use the same set of measures as in the EPA’s approach to setting the goals, or the state may use other or additional measures to achieve the required reductions. The plan must include a process for reporting on plan implementation, progress toward achieving CO₂ goals, and implementation of corrective actions, if necessary. No less than every two years, beginning January 1, 2022, the state will be required to compare emission performance achieved...
by affected EGUs in the state with the emissions performance projected in the state plan, and report that to the EPA.

In this action, the EPA is also proposing guidelines for states to use in developing their plans. These guidelines include approvability criteria, requirements for state plan components, the process and timing for state plan submittal and the process and timing for demonstrating achievement of the 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 plan guidelines provide the states with the ability to achieve the full reductions over a multi-year period, through a variety of reduction strategies, using state-specific or 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 contemplate in developing their plans.

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

ii. State plan components

The EPA is proposing to evaluate and approve state plans based on four general criteria: 1) enforceable measures that reduce EGU 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 biennial 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. The proposed components of states plans are:

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

iii. Process for state plan submittal and review

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 _rather than_ 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

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8 The President’s Climate Action Plan, June 2013, available at [http://www.whitehouse.gov/sites/default/files/image/president27s_climateactionplan.pdf](http://www.whitehouse.gov/sites/default/files/image/president27s_climateactionplan.pdf)
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 an optional two-phased submittal process for state plans. Each state would be required to submit its plan by June 30, 2016. However, if a state needs additional time to submit a complete plan, then the state must notify the 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. To be approvable, the initial plan must include specific components, including a description of the plan approach, initial quantification of the level of emission performance that will be achieved in the plan, a commitment to maintain existing measures that limit CO₂ emissions, and an explanation of the path to completion, as described in Section VIII.E of this preamble.

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. If given an extension, a
state would have until June 30, 2017, to submit a complete
plan if the geographic scope of the plan is limited to that
state. 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 four month period provided in the EPA
framework regulations to a six month review and approval
period.

v. Timing of compliance

The agency is proposing that states must begin to make
reductions by 2020 and 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. The first alternative option includes the addition of a required second submittal by each state in 2025 showing whether its plan measures would maintain the final emission performance level after 2030. The second alternative option is a 5-year period for compliance, in combination with a less stringent set of CO₂ emission performance levels. These options are fully described in Section VIII of this preamble.

The EPA is also proposing that measures that a state takes after the date of this proposal, and which result in CO₂ emission reductions during the plan period, would apply toward achievement of the state’s CO₂ emission goal. Thus, states with existing programs and policies, and states that put in place new programs and policies early, will be better positioned to achieve the goals.
To respond to requests from states for methodologies, tools, and information to assist them in designing and implementing their plans, the EPA, in consultation with the U.S. Department of Energy and other federal agencies, as well as states, is collecting and developing available resources and is making those resources available to the states.\(^{10}\)

3. Projected national-level emission reductions

Under the proposed guidelines, the EPA projects annual CO\(_2\) reductions of 26 to 30 percent below 2005 levels. These guidelines will also result in important reductions in emissions of criteria air pollutants, including sulfur dioxide (SO\(_2\)), nitrogen oxides (NO\(_x\)) and directly emitted fine particulate matter (PM\(_{2.5}\)).

4. Costs and benefits

Actions taken to comply with the proposed guidelines will reduce emissions of CO\(_2\) and other air pollutants, including SO\(_2\), NO\(_x\) and PM\(_{2.5}\), from the electric power industry. States will make the ultimate determination as to how the emission guidelines are implemented. Thus, all costs and benefits reported for this action are illustrative estimates.

\(^{10}\) [www2.epa.gov/carbonpollutionstandardstoolbox](http://www2.epa.gov/carbonpollutionstandardstoolbox)
Assuming that states comply with the guidelines collaboratively (referred to as the regional compliance approach), the EPA estimates that, in 2020, this proposal will yield monetized climate benefits of approximately $17 billion (2011$) using a 3 percent discount rate (model average) relative to the 2020 base case. The air pollution health co-benefits associated with reducing exposure to ambient PM$_{2.5}$ and ozone through emission reductions of precursor pollutants in 2020 are estimated to be $15 billion to $34 billion using a 3 percent discount rate and $13 billion to $31 billion (2011$) using a 7 percent discount rate relative to the 2020 base case. The annual compliance costs are estimated using the Integrated Planning Model (IPM) and include demand-side energy efficiency program and participant costs as well as monitoring and reporting costs. Total compliance costs of this proposal are approximately $5.4 billion (2011$) in 2020. The quantified net benefits (the

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1. 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 CO$_2$ emissions in a given year – to analyze CO$_2$ 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 percent discount rate.
difference between monetized benefits and compliance costs) in 2020 are estimated to be $26 billion to $46 billion (2011$) using a 3 percent discount rate (model average). Climate benefits are approximately $30 billion in 2030 using a 3 percent discount rate (model average, 2011$) relative to the 2030 base case assuming a regional compliance approach for the proposal. Health co-benefits are estimated to be approximately $24 to $55 billion (3 percent discount rate) and $21 to $50 billion (7 percent discount rate) relative to the 2030 base case (2011$). In 2030, total compliance costs for the proposed option regional approach are approximately $7.3 billion (2011$). The net benefits for this proposal increase to approximately $47 billion to $78 billion (3 percent discount rate model average, 2011$) in 2030 for the proposed option regional compliance approach.

In comparison, if states choose to comply with the guidelines on a state-specific basis (referred to as state compliance approach), rather than collaboratively the climate benefits in 2020 are expected to be approximately $18 billion (3 percent discount rate, model average, 2011$). Health co-benefits are estimated to be $15 to $36 billion (3 percent discount rate) and $14 to $33 billion (7 percent discount rate). Net benefits are estimated to range from $26 to $46 billion (3 percent model average discount rate, 2011$). Climate benefits are
approximately $31 billion in 2030 using a 3 percent discount rate (model average, 2011$) relative to the 2030 base case assuming a state compliance approach. Health co-benefits are estimated to be approximately $25 to $58 billion (3 percent discount rate) and $23 to $53 billion (7 percent discount rate) relative to the 2030 base case (2011$). In 2030, total compliance costs for the state approach are approximately $8.8 billion (2011$). In 2030, these net benefits are estimated to be approximately $47 to $80 billion (3 percent discount rate, 2011$) assuming a state compliance approach.

There are additional important benefits that the EPA could not monetize. These unquantified benefits include climate benefits from reducing emissions of non-CO₂ greenhouse gases (e.g., nitrous oxide and methane)¹² and co-benefits from reducing direct exposure to SO₂, NOₓ, and hazardous air pollutants (e.g., mercury and hydrogen chloride), as well as from reducing ecosystem effects and visibility impairment.

¹²Although CO₂ is the predominant greenhouse gas released by the power sector, electricity generating units also emit small amounts of nitrous oxide and methane. See RIA Chapter 2 for more detail about power sector emissions and the U.S. Greenhouse Gas Reporting Program’s power sector summary, http://www.epa.gov/ghgreporting/ghgdata/reported/powerplants.htm l
Based upon the foregoing, it is clear that the monetized benefits of this proposal are substantial and far outweigh the costs.

B. Organization and Approach for this Proposed Rule

This action presents the EPA’s proposed emission guidelines for states to consider in developing plans to reduce GHG emissions from the electric power sector. Section II provides background on climate change impacts from GHG emissions, GHG emissions from fossil fuel-fired EGUs, and the utility power sector and CAA section 111(d) requirements. Section III presents a summary of the EPA’s stakeholder outreach efforts, key messages provided by stakeholders, state policies and programs that reduce GHG emissions, and conclusions. In Section IV of the preamble, we present a summary of the rule requirements and the legal basis for these, 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 and potential interactions with other EPA rules are described in Section IX. Impacts of the proposed action are then...
described in Section X, followed by a discussion of statutory and executive order reviews in Section XI and the statutory authority for this action in Section XII.

We note that this rulemaking overlaps in certain respects with two other related rulemakings: the January 2014 proposed rulemaking that the EPA published on January 8, 2014 for CO2 emissions from newly constructed affected sources\(^{13}\), and the rulemaking for modified and reconstructed sources that the EPA is proposing at the same time as this rulemaking. Each of these three rulemakings is independent of the other two, and each has its own rulemaking docket. Accordingly, commenters who wish to comment on any aspect of this rulemaking, including a topic that overlaps an aspect of one or both of the other two related rulemakings, should make those comments on this rulemaking.

II. Background

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

A. Climate Change Impacts from GHG Emissions

\(^{13}\) 79 FR 1430
In 2009, the EPA Administrator issued the document known as the Endangerment Finding under CAA section 202(a)(1). In the Endangerment Finding, which focused on public health and public welfare impacts within the United States, the Administrator found that elevated concentrations of GHGs in the atmosphere may reasonably be anticipated to endanger public health and welfare of current and future generations. We summarize these adverse effects on public health and welfare briefly here.

1. Public health impacts detailed in the 2009 Endangerment Finding

Climate change caused by human emissions of GHGs threatens public health in multiple ways. By raising average temperatures, climate change increases the likelihood of heat waves, which are associated with increased deaths and illnesses. While climate change also increases the likelihood of reductions in cold-related mortality, evidence indicates that the increases in heat mortality will be larger than the decreases in cold mortality in the United States. Compared to a future without climate change, climate change is expected to increase ozone pollution over

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broad areas of the U.S., including in the largest metropolitan areas with the worst ozone problems, and thereby increase the risk of morbidity and mortality. Other public health threats also stem from projected increases in intensity or frequency of extreme weather associated with climate change, such as increased hurricane intensity, increased frequency of intense storms, and heavy precipitation. Increased coastal storms and storm surges due to rising sea levels are expected to cause increased drownings and other health impacts. Children, the elderly, and the poor are among the most vulnerable to these climate-related health effects.

2. Public welfare impacts detailed in the 2009 Endangerment Finding16

Climate change caused by human emissions of GHGs also threatens public welfare in multiple ways. Climate changes are expected to place large areas of the country at serious risk of reduced water supplies, increased water pollution, and increased occurrence of extreme events such as floods and droughts. Coastal areas are expected to face increased risks from storm and flooding damage to property, as well as adverse impacts from rising sea level, such as land loss due to inundation, erosion,

wetland submergence and habitat loss. Climate change is expected to result in an increase in peak electricity demand, and extreme weather from climate change threatens energy, transportation, and water resource infrastructure. Climate change may exacerbate ongoing environmental pressures in certain settlements, particularly in Alaskan indigenous communities. Climate change also is very likely to fundamentally rearrange U.S. ecosystems over the 21st century. Though some benefits may balance adverse effects on agriculture and forestry in the next few decades, the body of evidence points towards increasing risks of net adverse impacts on U.S. food production, agriculture and forest productivity as temperature continues to rise. These impacts are global and may exacerbate problems outside the U.S. that raise humanitarian, trade, and national security issues for the U.S.

3. New scientific assessments

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

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

In addition, these assessments highlight the urgency of the situation as the concentration of 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.¹⁷ In fact, that assessment stated that “the magnitude and rate of the present greenhouse gas increase place the climate system in what could be one of the most severe increases in radiative forcing of the global climate system in Earth history.”¹⁸

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

Emissions of carbon dioxide from the burning of fossil fuels have ushered in a new epoch where human

¹⁸ Id., p.138.
activities will largely determine the evolution of Earth’s climate. Because carbon dioxide in the atmosphere is long lived, it can effectively lock Earth and future generations into a range of impacts, some of which could become very severe. Therefore, emission reductions choices made today matter in determining impacts experienced not just over the next few decades, but in the coming centuries and millennia.\footnote{National Research Council, Climate Stabilization Targets, p. 3.}

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

The recently released USGCRP “Climate Change Impacts” assessment\footnote{U.S. Global Change Research Program, Climate Change Impacts in the United States: The Third National Climate Assessment. Available at http://nca2014.globalchange.gov/} emphasizes that climate change is already happening now and it is happening in the United States. The assessment documents the increases in some extreme weather and climate events in recent decades, the damage and disruption to infrastructure and agriculture, and projects continued increase...
and more severe changes across a wide range of peoples, sectors, and ecosystems.

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

Finally, it should be noted that the concentration of carbon dioxide in the atmosphere continues to rise dramatically.

In 2009, the year of the Endangerment Finding, the average concentration of carbon dioxide as measured on top of Mauna Loa was 387 parts per million. The average concentration in 2013 was 396 parts per million. And the monthly concentration in April of 2014 was 401 parts per million, the first time a monthly average has exceeded 400 parts per million since record keeping began, and for at least the past 800,000 years according to ice core records.

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

21 ftp://aftp.cmdl.noaa.gov/products/trends/co2/co2_annmean_mlo.txt
22 http://www.esrl.noaa.gov/gmd/ccgg/trends/
of CO₂, 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 (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 of GHGs, including CO₂ emissions, for the years 1990, 2005 and 2012.

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>
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<tbody>
<tr>
<td>Energy</td>
<td>5,260.1</td>
<td>6,243.5</td>
<td>5,498.9</td>
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<tr>
<td>Industrial Processes</td>
<td>316.1</td>
<td>334.9</td>
<td>334.4</td>
</tr>
<tr>
<td>Solvent and Other</td>
<td>4.4</td>
<td>4.4</td>
<td>4.4</td>
</tr>
</tbody>
</table>


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

### Product Use

<table>
<thead>
<tr>
<th></th>
<th>1990</th>
<th>2005</th>
<th>2012</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Agriculture</strong></td>
<td>473.9</td>
<td>512.2</td>
<td>526.3</td>
</tr>
<tr>
<td><strong>Land Use, Land-Use</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Change and Forestry</strong></td>
<td>13.7</td>
<td>25.5</td>
<td>37.8</td>
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<td><strong>Waste</strong></td>
<td>165.0</td>
<td>133.2</td>
<td>124.0</td>
</tr>
<tr>
<td><strong>Total Emissions</strong></td>
<td>6,233.2</td>
<td>7,253.8</td>
<td>6,525.6</td>
</tr>
<tr>
<td><strong>Land Use, Land-Use</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Change and Forestry</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>(Sinks)</strong></td>
<td>(831.3)</td>
<td>(1,030.7)</td>
<td>(979.3)</td>
</tr>
<tr>
<td><strong>Net Emissions (Sources</strong></td>
<td>5,402.1</td>
<td>6,223.1</td>
<td>5,546.3</td>
</tr>
<tr>
<td><strong>and Sinks)</strong></td>
<td></td>
<td></td>
<td></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 77.7 percent of total 2012 GHG emissions. In 2012, fossil fuel combustion by the electric power sector -- entities that burn fossil fuel and whose primary business is the generation of electricity -- accounted for 38.7 percent of all energy-related CO₂ emissions.

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

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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 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

Table 2. U.S. GHG Emissions from Generation of Electricity from Combustion of Fossil Fuels (Tg CO₂)²⁸

<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</td>
<td>1,820.8</td>
<td>2,402.1</td>
<td>2,022.7</td>
</tr>
<tr>
<td>from coal</td>
<td>1,547.6</td>
<td>1,983.8</td>
<td>1,511.2</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>

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 CAA section 111(d) contemplates states

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29 CAA §111(b)(1)(A).
30 See 40 CFR 60 subparts Cb – OOOO.
31 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.” 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. 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 has one or more affected EGUs located in its area of Indian

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32 CAA section 111(d)(2)(A).
33 CAA section 111(d)(2)(A).
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 months of the due date for those plans, although the EPA has authority to extend those deadlines. 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)). In addition, the agency has regulated additional pollutants under CAA section 111(d) in conjunction with CAA section 129. The agency has not previously regulated CO₂ 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 characteristics of carbon pollution and the interconnected nature of the power sector. The manner in which EGUs are currently operated such that operators themselves treat increments of generation as interchangeable between and among sources in a way that creates options for relying on varying utilization levels, lowering carbon generation, and reducing demand as components of the overall method for reducing 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 Presidential 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.

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

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

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

This outreach process has produced a wealth of information, which has informed this proposal significantly. The pre-proposal outreach efforts far exceeded what is required of the agency in the normal course of a rulemaking process, and the EPA expects that the dialog with states and stakeholders will continue.
throughout the process and even after the rule is finalized. The EPA recognizes the importance of working with all stakeholders, and in particular with the states, to ensure a clear and common understanding of the role the 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 use resources prudently and enabled a variety of the EPA staff involved in the development and ultimate implementation of this upcoming rule to attend and learn from the views expressed.

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

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

4. State officials

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

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

5. Tribal officials

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

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

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

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

6. Industry representatives

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

7. Electric utility representatives

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

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

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

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

9. Representatives from non-governmental organizations

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

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

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

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

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

10. Labor

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 senior officials and staff met with union representatives that included the United Mine Workers of America, SMART, 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
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 via physical changes at the source to those that also are implementable across the broader power generation system. Opinions varied about how broader system measures could factor into programs to reduce carbon pollution. Some stakeholders recommended that system-wide measures be allowed for compliance, but not factored into the carbon improvement goals the EPA establishes, while others recommended that system-wide measures be factored into the goals. Among the arguments and information offered by stakeholders who suggested that states be encouraged to incorporate system-wide measures into their state plans and that EGU operators be encouraged to rely on such measures were examples and discussions of the significant extent to which dispatch, end use energy efficiency and renewable energy had already proven to be successful strategies for reducing EGU CO2 emissions. Some state and industry representatives favored goals that they described as based on measures implementable only within the facility “fence line” (i.e., measures implementable
only at the source). Many stakeholders stated that the EPA should not require the state plans to impose on the affected EGUs legal responsibility for the full amount of required 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 because of the state legislative schedule and/or regulatory process. In some cases, approval of a plan through a state’s legislative or regulatory process could take one year or more after the plan has already been developed. Additional time would also allow and encourage multi-state and regional partnerships and programs.

Many stakeholders also supported flexibility in the timing of implementation of the state plans and power sector compliance with the goals in the state plans. Such flexibility, some stakeholders asserted, would accommodate the diverse GHG mitigation potential of states and support more cost-effective approaches to achieving 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, a number of ideas were put forward that are not fully reflected in this proposal. We invite public comment on these 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, via a demonstration that the state program achieves equivalent or better carbon intensity for the regulated sector; mass-based equivalency, via a demonstration that the program achieves equal or greater emission reductions relative to what would be achieved by the federal approach; or a market price-based equivalency, via a demonstration that the program reflects a carbon price comparable to or greater than the cost-effectiveness benchmark used by the EPA in designing the program. The EPA is proposing a way to demonstrate equivalency and that is discussed in Section VIII.

3. Power plant-specific assessment

Other stakeholders suggested that an “inside the fence” plant- or unit-specific assessment linked to the availability of control at the source such as heat rate improvements should be
considered. They indicated that once plant-specific goals are established based on on-site 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 fuel-fired EGUs through, for example, renewable portfolio standards (RPS) and energy efficiency resource standards (EERS), which alter the mix of energy supply and reduce energy demand. States have developed their policies and programs with stakeholder input and tailored them to their own circumstances and priorities. Their leadership and experiences provided the EPA with important information about best practices to build upon in this proposed rule. As directed by the
Presidential Memorandum, the EPA is, with this proposal to reduce power plant carbon pollution, building on actions already underway in states and the power sector.

1. Market-based emission limits

Nine states actively participate in the Regional Greenhouse Gas Initiative (RGGI), a market-based CO₂ emission reduction program addressing EGUs that was established in 2009. 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

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45 The nine states include Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont.
sources flexibility to make emission reductions where reduction 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.⁴⁶ 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.⁴⁷ Through 2012, for example, the RGGI states invested approximately $460 million of proceeds into energy efficiency programs.⁴⁸ 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.⁴⁹

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

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⁴⁹ Id.
participating states fell by more than 40 percent.\textsuperscript{50} \textit{RGGI was not the primary driver for these reductions but the reductions led RGGI-participating states to adjust the CO2 emission limits.}\textsuperscript{51} 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 EGU 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.\textsuperscript{52}

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.\textsuperscript{53} 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

\textsuperscript{51} The first three-year control period under RGGI, establishing CO2 emission limits for EGU, began on January 1, 2009.
metric tons of CO₂ equivalent by 2025, a 25 percent reduction from 2005 power sector emission levels. \(^{54}\) 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.\(^ {55}\)

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


\(^{55}\) Id.
emission rate of either 1450 pounds CO₂/MWh (based on output) or 160 pounds of CO₂/MMBtu (based on input). ⁵⁶

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. ⁵⁷

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

⁵⁶ 6 New York CoCodes, Rules & Regulations. Part 251 (Adopted June 28, 2012)
⁵⁷ OR SB 101 (2000); Washington Revised Code ch.80.80 (2013); Wash SB 6001 (2007)
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 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 CO₂ emissions from generation in Colorado by 28 percent by 2020.

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-fired EGUs and, thereby, lead to reductions in GHG
emissions by meeting a portion of the demand for electricity
through renewable or other energy sources.

In 2007, the Minnesota legislature amended the state’s 2001
renewable energy objective and established a renewable energy
standard (RES) requiring at least 25 percent of all electricity
generated or purchased in Minnesota to come from renewable
energy by 2025. The standard sets requirements and timetables,
beginning in 2010, that vary based on the provider. For example,
in 2011, Xcel Energy had a requirement to generate or purchase
15 percent of its total retail sales from renewable energy while
all other utilities had a target of 7 percent of total retail
sales. According to the latest Minnesota Department of Commerce
report to the legislature on progress, all utilities subject to
the standard met it for 2011 and were on track to meet their
2012 goals.61 The 2012 requirement increased to 18 percent of
total retail sales for Xcel Energy and 12 percent for all other

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61 Report to the Minnesota Legislature: Progress on Compliance By
Electric Utilities With The Minnesota Renewable Energy Objective
Department of Commerce, Division of Energy Resources January
14, 2013;
utilities. 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.

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

62 Id.
63 Minnesota Statutes 2013, Section 216B.1691, Subdivision 2f. Solar Energy Standard
https://www.revisor.mn.gov/statutes/?id=216b.1691
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 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 about $5 billion in 2012. Based on Lawrence Berkeley National Laboratory (LBNL) projections, spending is projected to reach $8.1 billion in 2025.

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.

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.” It requires its investor-owned utilities to meet electricity load “through all available energy efficiency and demand reduction resources that are cost-

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68 December 27, 2013 Letter from Mary D. Nichols, Chairman of California Air Resources Board, to EPA Administrator Gina McCarthy.
effective, reliable and feasible. 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.” 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.” Between 2010 and 2011, these programs are estimated to have reduced CO₂ by 3.8 million tons.

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. Vermont law requires that the energy efficiency utility

70 Cited in December 27, 2013 Letter from Mary D. Nichols, Chairman of California Air Resources Board, to EPA Administrator Gina McCarthy.
71 Id.
72 Id.
http://psb.vermont.gov/utilityindustries/eeu/generalinfo/creationandstructure
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. In 2013, Efficiency Vermont, the PSB-appointed energy efficiency utility, achieved annual savings of 1.66 percent of the state’s electricity sales, at a cost of 4.1 cents per kilowatt-hour, lower than the cost of comparable electric supply in the same year, which was 8.4 cents per kWh. Efficiency Vermont projects a net lifetime economic value to Vermont of more than $60 million from the 2013 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

76 Id.
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 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-

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79 Id.
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 application of a number of approaches. Throughout the development of this proposed rule, the EPA considered the states’ experiences and lessons learned regarding the design and implementation of successful GHG mitigation programs. The agency also fully considered input from stakeholders during the development of this proposed rulemaking.

Considering all input from stakeholders, the agency recognizes that the most cost-effective approach to reducing GHG emissions from the power sector under CAA section 111(d) is to follow the lead of numerous states and not only to identify

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81 Id.
82 Id.
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Deleted: improve
improvements in the efficiency of fossil fuel-fired EGUs as a component of BSER, but also include in the BSER determination the EGU-emissions-reduction opportunities that states have already demonstrated to be successful in relying on lower- and zero-emitting generation and reduced electricity demand.

CAA section 111(d) sets up a partnership between the EPA and the states. In the context of that partnership, the EPA recognizes the importance of each state having the flexibility to design a cost-effective program tailored to its own specific circumstances. The agency also recognizes, as many states 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 CO₂ 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. Reducing the carbon intensity of generation at individual affected EGUs through heat rate improvements.

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

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

4. Reducing emissions from affected EGUs in the amount that results from the use of demand-side energy efficiency that reduces the amount of generation required.
The proposed state goals reflect the following stringency of application of the measures in each of the building blocks: Block 1, improving average heat rate of coal-fired steam EGUs by six percent; block 2, displacing coal-fired steam and oil/gas-fired steam generation in each state by increasing generation from existing NGCC capacity in that state toward a 70 percent target utilization rate; block 3, including some amount of generation from 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 efficiency efforts to reach 1.5 percent annual electricity savings in the 2020-2029 period.

Based on the EPA’s application of the BSER to each state, the EPA is proposing to establish, as part of the emission guidelines, state-specific goals, expressed as average emission rates for fossil fuel-fired EGUs. Each state’s goals comprise the EPA’s determination of the emission limitation achievable through application of the BSER in that state. For each state, the EPA is proposing an interim goal for the phase-in period from 2020 to 2029 and the final goal that applies beginning in
2030. The proposed goals for each state are listed in Section VII, below. The EPA is proposing that measures that a state takes after the date of this proposal, and which result in CO2 emission reductions during the plan period, would apply toward achievement of the state’s CO2 goal.

The EPA is further proposing, as part of the plan guidelines, timetables for states to submit their plans. The agency expects to finalize this rulemaking by June 2015, and we are proposing to require that each state submit its plan to the EPA by June 30, 2016. However, if a state needs additional time to submit a complete plan, then the state must notify the 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. 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 states the option of translating the EPA-determined goal, which will be rate-based, to a mass-based goal. For states participating in a multi-state approach, the individual state performance goals in the emission guidelines would be replaced with an equivalent multi-state performance goal. The EPA is also proposing that in their plans, whether single state or multi-state, states may not adjust the stringency of the goals set by the EPA.

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

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

The EPA is also proposing, as part of its emission guidelines, that plan approvability be based on four general criteria: 1) enforceable measures that reduce EGU 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.
achievement of the required emission performance level, 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 final 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 in its area of Indian country, the tribe would have the opportunity, but not

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83 The EPA is aware of at least four affected EGUs located in Indian country: two on Navajo lands, the Navajo Generating Station and the Four Corners Generating Station, one on Ute lands, the Bonanza Generating Station, and one on Fort Mojave lands, the South Point Energy Center. The affected EGUs at the first three plants are coal-fired EGUs. The fourth affected EGU is an NGCC facility.
the obligation, to establish a CO₂ emission performance standard and a CAA section 111(d) plan for its area of Indian country.

B. Summary of Legal Basis

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 provisions concerning the air pollutants covered under CAA section 111(d) to authorize the EPA to regulate CO₂ from EGUs. We recognize that CAA section 111(d) applies to sources that, if they were new sources, would be covered under a CAA section 111(b) rule. The EPA intends to complete 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. According to the EPA, 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

84 The EPA is not re-opening that interpretation in this rulemaking.
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 the achievable limits of 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 as being technically feasible and reasonable in terms of cost. Heat 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 fuel-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 emission performance level, but instead impose requirements on other affected entities - for requirements, such as renewable energy and demand-side energy efficiency measures, that would avoid CO₂ emissions from the affected EGUs. The EPA solicits comment on whether such requirements on other affected entities may be authorized as standards of performance or
implementing measures in a state’s CAA section 111(d) plan. The EPA also solicits comment on whether state plans must impose all of the legal responsibility for achieving the emission performance level on the affected EGUs. We note that even if as a legal matter states would be required to impose responsibility in such a way, the state plan – and state policy – nevertheless still could include requirements on other affected entities in order to facilitate, as a practical and economic matter, implementation of measures that avoid CO₂ emissions from 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 efficacious 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), \( \text{CO}_2 \) emissions from EGUs, under the Agency’s construction of the ambiguous provisions in CAA section 111(d)(1)(A)(i) that identify the air pollutants subject to CAA section 111(d). The ambiguities stem from apparent drafting errors that occurred during enactment of the 1990 CAA Amendments, which revised section 111(d).

During the 1990 CAA Amendments, the House of Representatives and the Senate each passed an amendment to CAA section 111(d)(1)(A)(i). The two amendments differed from each other, and were not reconciled during the Conference Committee and, as a result, both were enacted into law. As amended, CAA section 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]... [or 112(b)]...” 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

\[^{85}\text{Pub. L. No. 101-549, §108(g), 104 Stat. at 2467 (Nov. 15, 1990).}\]
\[^{86}\text{Pub. L. No. 101-549, §302(a), 104 Stat. at 2574 (Nov. 15, 1990).}\]
these circumstances, the EPA may reasonably construe the
provision to authorize the regulation of GHGs under CAA section
111(d).

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

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

B. Authority to Regulate EGUs

Before the EPA finalizes this CAA section 111(d) rule, the
EPA will finalize a CAA section 111(b) rulemaking regulating CO2
emissions from new EGUs, which will provide the requisite
predicate for applicability of CAA section 111(d).

CAA section 111(d)(1) requires the EPA to promulgate
regulations under which states must submit state plans
regulating “any existing source” of certain pollutants “to which
a standard of performance would apply if such existing source
were a new source.” A “new source” is “any stationary source,
the construction or modification of which is commenced after the
publication of regulations (or, if earlier, proposed regulations) prescribing a standard of performance under [CAA section 111] which will be applicable to such source.” It should be noted that these provisions make clear that a “new source” includes one that undertakes either new construction or a modification. It should also be noted that EPA’s implementing regulations define “construction” to include “reconstruction,” which the implementing regulations go on to define as the replacement of components of an existing facility to an extent that (i) the fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility, and (ii) it is technologically and economically feasible to meet the applicable standards.

Under CAA section 111(d)(1), in order for existing sources to become subject to that provision, the EPA must promulgate standards of performance under CAA section 111(b) to which, if the existing sources were new sources, they would be subject. Those standards of performance may include ones for sources that undertake new construction, modifications, or reconstructions. The EPA is in the process of promulgating two rulemakings under CAA section 111(b) for CO₂ emissions from affected sources. The EPA proposed the first, which applies to affected sources
undertaking new constructions, by notice dated January 8, 2014, which we refer to as the January 2014 Proposal. The EPA is proposing the second, which applies to affected sources undertaking modifications or reconstructions, concurrently with this CAA section 111(d) proposal. The EPA will complete one or both of these CAA section 111(b) rulemakings before or concurrently with this CAA section 111(d) rulemaking, which will provide the requisite predicate for applicability of CAA section 111(d).

C. Affected Sources

The EPA is proposing that, for the emission guidelines, an affected EGU is any fossil fuel-fired EGU that was in operation or had commenced construction as of January 8, 2014, and is therefore an “existing source” for purposes of CAA section 111, and that in all other respects would meet the applicability criteria for coverage under the proposed GHG standards for new fossil fuel-fired EGUs (79 FR 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 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 this proposal concerning applicability is the same as that for the January 8, 2014 proposal, sections V.A-B. See 79 FR at 1,459/1 – 1,461/2. We incorporate that discussion by reference here.

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

In the present rulemaking, the EPA is proposing emission guidelines for the two categories and is 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 CO$_2$ mitigation measures, such as shifting generation from higher to lower-carbon intensity generation among existing sources (e.g., shifting from boilers to NGCC units) or facilitating emissions trading among sources. Because the two categories are pre-existing and the EPA would not be subjecting any additional sources to regulation, the combined category would not be considered a new category that the EPA must list under CAA section 111(b)(1)(A). As a result, this proposal does not list a new category under section 111(a)(1)(A), nor does this proposal revise either of the two source categories – steam-generating boilers and combustion turbines – that the EPA has already listed under that provision. Thus, the EPA would not be required to make a finding that the combined category causes or contributes significantly to air pollution which may reasonably be anticipated to endanger public health or welfare.

In addition, the EPA is 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 experiences of states and the industry and the EPA's outreach with stakeholders as described above, the EPA has identified multiple measures currently in use for achieving CO₂ emissions from existing fossil fuel-fired EGUs. For purposes of determining the "best system of emission reduction ... adequately demonstrated" (BSER) and developing state emission performance goals, we have screened the measures and grouped those we are proposing to consider further at this time into four categories, which we call "building blocks." We provide an overview of these building blocks in subsection VI.B. and more detailed discussion of each block in subsection VI.C. In subsection VI.D. we discuss possible combinations of the building blocks, and in subsection VI.E., we explain why as a legal matter all four building blocks, taken together, constitute the basis for the BSER, which in turn serves as the basis for the standards of performance that the states must include in their state plans, as CAA section 111(d) requires.

As discussed in Section III, we are mindful of numerous and varied stakeholder concerns, including the need to achieve meaningful CO₂ emission reductions and to recognize and take advantage of the progress already made by existing programs. Like stakeholders, we are attentive to the need to maintain electric system reliability and to minimize adverse impacts on
electricity and fuel prices and on assets that have already been improved by installation of controls for other kinds of pollution. Many of these considerations align with our approach to 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 operate with differing circumstances and policy preferences. For example, states have differing access to specific fuel types, and the variety of types of EGUs operating in different states is broad and significant. States are part of assorted EGU dispatch systems and vary in the amounts of electricity that they import and export. For these reasons, we also recognize and appreciate the value in allowing and promoting 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 for those states.

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 cumulative emissions reductions that sustained implementation of other actions, such as demand-side energy efficiency programs, may achieve over time.

B. Building Blocks for the Best System of Emission Reduction

This subsection summarizes the EPA’s analytic approach to determining the best system of emission reduction (BSER) for CO₂ emissions from existing EGUs. Further discussion of particular measures and how they form the basis of the BSER is provided below in subsections VI.C and VI.D, respectively.

1. Overview of approach

In considering the appropriate scope of the proposed BSER, the EPA evaluated three basic groupings of strategies for reducing CO₂ emission from EGUs: (i) reductions achievable through improvements in individual EGUs’ emission rates (referred to throughout this preamble as "building block 1");
(ii) EGU CO2 emissions reductions achievable through re-dispatch from affected steam EGUs to affected NGCC units ("building block 2"); and (iii) EGU CO2 emissions reductions achievable by meeting demand for electricity or electricity services through expanded use of low- or zero-carbon generating capacity ("building block 3") and of increased demand-side energy efficiency ("building block 4").

As described in the remainder of this section, the EPA concluded that while certain strategies within the first grouping clearly should be part of the BSER, it was not appropriate to limit consideration of the BSER to this first grouping, for several reasons. First, we determined that some strategies available in the other two groupings can reduce CO2 emissions from the fossil fuel-fired EGUs by significant amounts and at lower costs than some of the strategies in the first grouping. Second, we observed that strategies in all three groupings were already being pursued by states and sources taking advantage of the integrated nature of the electricity system, at least in part for the purpose of reducing CO2 emissions. Third, we were concerned that if measures from the first grouping that improve heat rates at coal-fired steam EGUs were implemented in isolation, without additional measures that encourage substitution of less carbon-intensive ways of
providing electricity services for more carbon-intensive
generation, the resulting increased efficiency of coal-fired
steam units would provide incentives to operate those EGUs more,
leading to smaller overall reductions in CO₂ emissions.⁸⁷ These
factors reinforced the appropriateness of our considering
strategies from all three groupings for purposes of determining
the BSER.

2. CO₂ reductions achievable through improvements in individual
EGUs’ emission rates

The first grouping of CO₂ emission reduction options that
EPA evaluated as potential options for the BSER consists of
measures that can reduce individual EGUs’ CO₂ emission rates
(i.e., the amount of CO₂ emitted per unit of electricity⁸⁸
output). These measures included improving the efficiency with
which EGUs convert fuel heat input to electricity output (i.e.,
heat rate improvements), applying carbon capture and storage
(CCS) technology, and substituting lower-carbon fuels such as

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⁸⁷ The potential for efficiency improvements to lead to increased
utilization is generally described as a “rebound effect.”
⁸⁸ For simplicity, in this subsection we refer to the energy
output produced by EGUs as electricity, recognizing that some
EGUs produce a portion of their energy output in other forms,
such as steam for heating or process uses. The discussion here
applies to both EGUs that produce only electricity and EGUs that
produce a combination of electricity and other energy output.
natural gas for higher-carbon fuels such as coal (i.e., natural gas co-firing or conversion).

Our assessment of heat rate improvements showed that these measures would achieve CO₂ emission reductions at low costs, although compared to other measures, the available reductions were relatively limited in quantity. Specifically, our analysis indicated that average CO₂ emission reductions of 1.3 to 6.7 percent could be achieved by coal steam EGUs through adoption of best practices, and that additional average reductions of up to four percent could be achieved through equipment upgrades.⁸⁹ Heat rate improvements pay for themselves at least in part through reductions in fuel costs, generally making this a relatively inexpensive approach for reducing CO₂ emissions. We estimated that CO₂ reductions of between four and six percent from overall heat rate improvements could be achieved on average across the nation’s fleet of coal steam EGUs for net costs in a range of $6 to $12 per metric ton.⁹⁰

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⁸⁹ These estimated ranges are averages applicable to the fleet of coal steam EGUs as a whole. Potential improvements at individual EGUs could be higher or lower.

⁹⁰ As noted above, in the absence of other kinds of CO₂ emission reduction measures, the emission reductions achievable through heat rate improvements could be offset to some extent by increased utilization of EGUs making the improvements (a “rebound effect”).
The EPA also examined application of CCS technology at existing EGUs. CCS offers the technical potential for CO₂ emission reductions of over 90 percent, or smaller percentages in partial applications. In the recently proposed Carbon Pollution Standards for new fossil fuel-fired EGUs (79 FR 1430), we found that partial CCS was adequately demonstrated for new fossil fuel-fired steam EGUs and integrated gasification combined cycle (IGCC) units. We also found that for these new units the costs were not unreasonable, either for individual units or on a national basis, and we proposed to find that application of partial CCS is the BSER. However, application of CCS at existing units would entail additional considerations beyond those at issue for new units. Specifically, the cost of integrating a retrofit CCS system into an existing facility would be expected to be substantial, and some existing EGUs might have space limitations. Further, the aggregated costs of applying CCS as a component of the BSER for the large number of existing fossil fuel-fired steam EGUs would be substantial and would be expected to affect the cost and potentially the supply of electricity on a national basis. For these reasons, although some individual facilities may find implementation of CCS to be a viable CO₂ mitigation option in their particular
circumstances, the EPA is not proposing and does not expect to finalize CCS as a component of the BSER for existing EGUs in this rulemaking.

Natural gas co-firing or conversion at coal-fired steam EGUs offers greater potential CO₂ emission reductions than heat rate improvements, but at a higher cost (although less than the cost of applying CCS technology). Because natural gas contains less carbon than an energy-equivalent quantity of coal, converting a coal-fired steam EGU to burn only natural gas would reduce the unit’s CO₂ emissions by approximately 40 percent. The CO₂ reductions are generally proportional to the amount of gas substituted for coal, so if instead the EGU continued to burn mostly coal while co-firing natural gas as, for example, 10 percent of the EGU’s total heat input, the CO₂ emission reductions would be approximately four percent. The EPA determined that the most significant cost associated with natural gas conversion or co-firing is likely to be the incremental cost of natural gas relative to the cost of coal. Using Energy Information Administration (EIA) fuel price projections, we estimated that the CO₂ reductions achieved

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91 CCS already has been or is being implemented at some existing EGUs, as noted in the discussion of CCS later in the preamble.
92 As noted later in this preamble, we are nevertheless seeking comment on the extent to which existing EGUs could implement CCS in order to improve our understanding.
through natural gas conversion or co-firing at an average coal-fired steam EGU would have costs ranging from approximately $83 to $150 per metric ton.\(^9\) Thus, although there have been past instances where coal-fired steam EGUs have been converted to natural gas, and we expect some additional future conversions where circumstances at individual EGUs make the option particularly attractive, for the industry as a whole we would expect that other approaches could reduce CO\(_2\) emissions from existing EGUs at lower cost. However, as noted later in the preamble, we are seeking comment on whether this option should be considered part of the BSER.

3. CO\(_2\) emission reductions achievable through re-dispatch from steam EGUs to NGCC units

The second grouping of CO\(_2\) emission reduction options evaluated by the EPA in the BSER analysis involves reducing emissions by shifting generation among affected EGUs. An obvious alternative to substituting natural gas for coal at individual steam EGUs through conversion or co-firing is instead to use natural gas to generate electricity at a different affected EGU with a better heat rate – notably a natural gas combined cycle

\(^9\) The lower end of the range is for conversion to 100 percent natural gas, which would allow EGUs to eliminate certain fixed operating and maintenance costs associated with coal use but not natural gas use.
(NGCC) unit – and to substitute that electricity for electricity from the coal-fired steam EGU, thus resulting in lower emissions from the coal-fired steam EGU and lower emissions from the set of affected EGUs overall. The electricity system is physically interconnected or networked and operated on an integrated basis across large regions. System operators routinely increase or decrease the electricity output of individual EGUs to respond to changes in electricity demand, equipment availability, and relative operating costs (or bid prices) of individual EGUs while observing reliability-related constraints. It has long been common industry practice for system operators to choose from among multiple EGUs when deciding which EGU to “dispatch” to generate the next increment of electricity needed to meet demand. Thus, the well-established practices of the industry support our evaluation of “re-dispatch” of generation from steam EGUs to NGCC units as a potential component of the BSER for reducing CO₂ emissions from existing EGUs.

NGCC units can produce as much as 46 percent more electricity from a given quantity of natural gas than steam.

* Strategies in this grouping also include shifting generation from steam EGUs burning oil or natural gas to more efficient NGCC units.
EGUs, making the re-dispatch approach a significantly less expensive way to reduce CO₂ emissions than conversion or co-firing of coal-fired steam EGUs to burn natural gas. For example, using the same EIA fuel cost projections as were used above to estimate the costs of natural gas conversion or co-firing, we estimated that the cost of CO₂ reductions achievable by substituting electricity from an existing NGCC unit for electricity from an average coal-fired steam EGU would be approximately $30 per metric ton.

Our analysis indicated that the potential CO₂ reductions available through re-dispatch from steam EGUs to NGCC units are substantial. As of 2012, there was approximately 245 GW of NGCC capacity in the United States, 196 GW of which was placed in service between 2000 and 2012. In 2012, the average utilization rate of U.S. NGCC capacity was 46 percent, well below the utilization rates the units are capable of achieving. In 2012, approximately 10 percent of NGCC plants operated at annual utilization rates of 70 percent or higher, and 19 percent of

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95 This estimate assumes an average heat rate of 10,434 Btu/kWh for coal fossil fuel-fired steam units between 400 and 600 MW and 7,130 Btu/kWh for NGCC units between 400 and 600 MW. See NEEDSv.5.13 at http://www.epa.gov/powersectormodeling/BaseCasev513.html.
96 EIA Form 860. In comparison, in 2012 there was 336 GW of coal steam capacity, of which 22 GW was placed in service between 2000 and 2012. Id.
NGCC units operated at utilization rates of at least 70 percent over the summer season. Average reported availability generally exceeds 85 percent. We recognize that the ability to increase NGCC utilization rates may also be affected by infrastructure and system considerations, such as limits on the ability of the natural gas industry to produce and deliver the increased quantities of natural gas, the ability of steam EGUs to reduce generation while remaining ready to supply electricity when needed in peak demand hours, and the ability of the electric transmission system to accommodate the changed geographic pattern of generation. However, these considerations have not limited past rapid increases in NGCC generation levels, as indicated by a 20 percent increase in natural gas consumption for electricity generation from 2011 to 2012.\textsuperscript{97} Further, the proposal’s compliance schedule provides flexibility and time for investment in additional natural gas and electric industry infrastructure if needed.

As discussed below in subsection VI.C.2, the above facts support our assessment that an average NGCC utilization rate in a range of 65 to 75 percent is a reasonable target for the amount of additional NGCC generation that could be substituted for higher carbon generation from steam EGUs as part of the

\textsuperscript{97} EIA Form 923.
BSER. If re-dispatch consistent with a target average NGCC utilization rate of 70 percent had been achieved in 2012, the combined CO₂ emissions of steam EGUs and NGCCs would have been reduced by approximately 13 percent.

Finally, we also note that mechanisms for encouraging re-dispatch as a CO₂ reduction measure have already been developed and applied in the industry. Under both RGGI and AB32, shifting generation from more carbon-intensive EGUs to less carbon-intensive EGUs is a way to facilitate compliance with regulatory requirements. In both cases, the industry has demonstrated the ability to respond to the regulatory requirements of these state programs.

4. CO₂ emission reductions achievable through other actions underway in the industry

The third grouping of CO₂ emission reduction options the EPA evaluated in the BSER analysis encompassed other measures already used in the industry and not included in the first two groupings. From our evaluation of re-dispatch as an option for reducing CO₂ emissions, it was apparent that relevant factors for consideration include the integrated nature of the electricity system and the fact that particular measures capable of reducing

Substitution would only occur to the extent that there is both NGCC capacity whose generation could be increased and steam EGUs whose generation could be decreased.
CO2 emissions at EGUs were already being used and would continue to be used throughout the industry, at least potentially for the purpose of compliance with CO2 emission reduction requirements. That observation led us to consider what other potential actions and options the industry was already using that had resulted in or could result in the reduction of CO2 emissions at EGUs. Again, many instances were observed as taking place incidental to the ongoing operation of the electricity system as well as taking place in response to specific CO2 emissions limits in place in states that have been implementing CO2 emissions reduction programs affecting the power sector. We concluded that there are two principal types of such potential options for measures that result in CO2 emission reductions at EGUs affected under this proposal: ongoing development and use of low- and zero-carbon generating capacity, and ongoing development and application of demand-side energy efficiency measures.

Low-and zero-carbon generating capacity provides electricity that can be substituted for generation from more carbon-intensive EGUs. More than half the states already have established some form of state-level renewable energy requirements, with targets calling on average for almost 20% of 2020 generation to be supplied from renewable sources. The EPA is unaware of analogous state policies to support development of
new nuclear units, but 30 states already have nuclear EGUs (with five units under construction) and the generation from these units is currently helping to avoid CO₂ emissions from fossil fuel-fired EGUs. Policies that encourage development of renewable energy capacity and discourage premature retirement of nuclear capacity could be useful elements of CO₂ reduction strategies and are consistent with current industry behavior. Costs of CO₂ reductions achievable through these policies have been estimated in a range from $10 to $40 per metric ton.

Demand-side energy efficiency programs reduce the demand for generation from existing fossil fuel-fired EGUs, and therefore eliminate the CO₂ emissions associated with the avoided generation as well, by producing electricity-dependent services with less electricity. More than 40 states already have established some form of demand-side energy efficiency policies, and individual states have avoided up to 13% of their electricity demand. Again, policies that encourage demand-side energy efficiency could be useful elements of CO₂ reduction strategies and are consistent with current industry behavior. Using conservatively high estimates of the costs of demand-side energy efficiency, the EPA estimates that the costs of CO₂ emission reductions achievable consistent with such policies would be in a range of $16 to $24 per metric ton.
5. Summary of building blocks for the best system of emission reduction

Based on the analytic approach summarized above, the EPA has identified the following four principal categories - “building blocks” - of measures that provide the foundation of our BSER determination for CO₂ emissions from existing EGUs:

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

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

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

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

Since they result either in improved operating efficiency or in reductions in mass emissions at existing EGUs, each of the four building blocks represents a demonstrated approach for reducing CO₂ emissions from affected EGUs that is already being
pursued in the power sector. In the next subsection, we discuss each of the building blocks at length. Our approach for applying the building blocks to each state’s circumstances in order to develop state goals is described in Section VII of this preamble.

C. Detailed Discussion of Building Blocks and Other Options Considered

In this section we discuss each of the building blocks in turn. For each building block, we provide our proposed assessment of the technical potential of the building block and the reasonableness of its costs within the context of the BSER determination, and we describe how we developed the data inputs used in the computations of state goals described in section VII. 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.

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

1. Building block 1 – heat rate improvements

The first category of approaches to reducing CO₂ emissions at affected fossil fuel-fired EGUs consists of measures that reduce the carbon intensity of generation at individual coal-fired steam EGUs⁹⁹ by improving heat rate. Heat rate improvements

⁹⁹ 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
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.

The EPA is aware of the potential for “rebound effects” from improvements in heat rates at individual EGUs. In this context, a rebound effect would occur where, because of an improvement in its heat rate, an EGU experiences a reduction in variable operating costs that makes the EGU more competitive relative to other EGUs and consequently raises the EGU’s generation output. The increase in the EGU’s CO₂ emissions associated with the increase in generation output would offset the reduction in the EGU’s CO₂ emissions caused by the decrease in its heat rate and rate of CO₂ emissions per unit of generation output. The extent of the offset would depend on the extent to which the EGU’s generation output increased (as well as the CO₂ 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).
emission rates of the EGUs whose generation was displaced). The EPA considers the rebound effect to be a potential concern if heat rate improvements were the only approaches being considered for the BSER, but believes that the effect can be addressed by establishing the BSER as a combination of approaches that includes not only heat rate improvements but also approaches that will prevent or discourage increases in generation output from coal-fired steam EGUs on average. The topic of potential rebound effects is discussed further in section VI.B above and sections VI.D and VI.E below. For purposes of the remainder of this subsection, no rebound effect is assumed.

Although heat rate improvements have the potential to reduce CO₂ emissions from all types of affected EGUs, the EPA’s analysis indicates the potential is significantly greater for coal-fired steam EGUs than for other EGUs, and for purposes of determining the best system of emission reduction EPA has therefore conservatively based its estimate of CO₂ emission reductions from heat rate improvements on coal-fired steam EGUs only.101 The remainder of this section focuses primarily on the EPA’s analysis of potential heat rate improvements from coal-fired steam EGUs. In the final subsection below we discuss our

101 States and EGUs would also be able to rely on CO₂ emission reductions achieved through heat rate improvements at other types of EGUs.
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 electrical energy output (and useful thermal energy in the case of cogeneration units). The current weighted-average annual heat rate of U.S. coal-fired EGUs in the range of 400 to 600 MW is approximately 10,434 Btu per net kWh. Because an EGU’s CO₂ 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.

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102 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.

103 See NEEDSv.5.13 at http://www.epa.gov/powersectormodeling/BaseCasev513.html. A small portion of some fossil fuel-fired EGU’s CO₂ emissions may come from sources other than fuel, such as limestone or other carbonates used to capture sulfur dioxide (SO₂) and/or hydrogen chloride (HCl) in a scrubber or dry injection system. However, CO₂ emissions from these reagents will also tend to be reduced by heat rate improvements, because reagent usage, and the associated CO₂ emissions, will decrease when the amount of fuel used decreases.
Several studies have examined the opportunities to employ heat rate improvements as a means of reducing CO₂ emissions from coal-fired power plants. Among these, a 2009 study by the engineering firm Sargent & Lundy 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 heat rate improvements in a range of approximately 4 to 12 percent. (We recognize that individual EGUs would only be able to implement the best practices or upgrades that were applicable to their specific designs or fuel types and that had not already been implemented.)

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

See chapter 2 of the GHG Abatement Measures TSD for details.
We have reviewed these data and have identified several “data apparent” instances where an EGU’s heat rate experienced a substantial improvement in a short time - presumably because of equipment upgrades installed at that point in time - that was then sustained. These heat rate improvements ranged from 3 to 8 percent. In combination with bottom-up engineering analysis and the further, more detailed EPA analysis of hourly data summarized below, the individual EGU heat rate histories provide a strong basis for considering heat rate improvement as a meaningful potential approach to reducing the carbon intensity of generation at individual affected fossil fuel-fired EGUs.

b. Amounts of heat rate improvements

In order to estimate the technical potential of heat rate improvement opportunities at existing fossil fuel-fired EGUs suggested by the discussion above, the EPA pursued two principal areas of analysis. The first area concerned the heat rate improvements that could be achieved by reducing heat rate variability at individual coal-fired EGUs through adoption of best practices for operation and maintenance. The second area concerned heat rate improvement opportunities that could be achieved through further equipment upgrades. Both analyses are summarized below along with our conclusions, and are discussed in greater detail in the GHG Abatement Measures TSD.
For the best practices analysis, the EPA worked with the hourly data reported to the EPA by affected EGUs subject to the monitoring and reporting requirements of 40 CFR Part 75. The reported data include hourly heat input and, for most reporting EGUs, hourly gross generation, making it possible to compute hourly gross heat rates. We used the hourly data to assess variability in the hourly gross heat rates of approximately 900 individual coal-fired steam EGUs over the period from 2002 to 2012. Specifically, the EPA evaluated the consistency with which individual EGUs maintained their hourly heat rates over time. We expected that a certain degree of short-term heat rate variability was caused by factors beyond operators' control, notably variation in hourly ambient temperature and hourly load, and preliminary analysis confirmed our expectation. We therefore controlled for variation in those factors by grouping the observed hourly heat rate data for each EGU into subsets corresponding to ranges of hourly ambient temperatures and hourly load levels. Temperature data are from the National Oceanic and Atmospheric Administration’s Integrated Surface Data, http://www.ncdc.noaa.gov/data-access/land-based-station-data/land-based-datasets/Integrated-surface-database-isd. Electrical generation data are from EPA’s Air Markets Program Data, http://ampd.epa.gov/ampd/.
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

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107 We examined whether the potential for heat rate improvement varied based on EGU characteristics such as capacity, boiler
for purposes of developing state-specific goals is that affected coal-fired steam EGUs on average could achieve a four percent improvement in heat rate through adoption of best practices to reduce hourly heat rate variability. This estimate corresponds to the elimination, on average across the fleet of affected EGUs, of 30 percent of the deviation from top-decile performance in the hourly heat rate for each EGU not attributable to hourly temperature and load variation. We also solicit comment on the use of estimates up to six percent, reflecting elimination on average of 50 percent of the deviation from top-decile performance.

For the equipment upgrade analysis, we evaluated potential opportunities to improve heat rates at affected EGUs through specific upgrades identified in the 2009 Sargent & Lundy study. In that study, Sargent & Lundy estimated ranges of potential heat rate improvement achievable through a variety of equipment upgrades. We screened the upgrades from the study to identify what we consider to be a reasonable subset of equipment upgrades that would generally be beyond the scope of investments we would expect to be made for purposes of achieving the best-practices heat rate improvements discussed above. Based on the average of the study’s ranges of potential heat rate improvements from the type, and location, and found no meaningful differences.
various upgrades in this subset, implementation of the full subset of appropriate opportunities at a single EGU could be expected to result in an aggregate heat rate improvement of approximately four percent (incremental to the improvement achievable from adoption of best practices). However, we recognize that this total may overstate the average equipment upgrade opportunity across all EGUs because some EGUs may have already implemented some of these upgrades. We therefore propose to use as a data input for purposes of developing state goals an estimate that, on average across the fleet of affected EGUs, only half of the full equipment upgrade opportunity just described remains – i.e., that for the fleet of affected EGUs as a whole, the technical potential for heat rate improvements from equipment upgrades incremental to the best-practices opportunity is on average two percent rather than four percent. We solicit comment on increasing this figure up to four percent.

Some of the measures available to EGUs for reducing their carbon intensity affect net heat rates rather than gross heat rates. Various EGU components such as pumps, fans, motors, and pollution control devices use electricity, a factor that is not accounted for in gross heat rates (that is, fuel used per unit of gross energy output) but is accounted for in net heat rates (that is, fuel used per unit of net energy output sent to the
electric grid or used for thermal purposes). The electricity used by these components, referred to as auxiliary or parasitic load, may represent from 4 to 12 percent of gross generation at a coal-fired steam EGU.\footnote{Electric Power Research Institute 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 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 opportunities for sources to improve their heat rates cost effectively.\footnote{As proposed, the state-specific goals are expressed in the form of CO₂ emissions per net MWh, and reporting requirements for}
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 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 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.
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, with the result that the net costs of heat rate improvements associated with reducing CO2 emissions from affected EGUs are relatively low.

The EPA’s most detailed estimates of the average costs required to achieve the full range of heat rate improvements
come from the 2009 Sargent & Lundy study discussed above. The 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 Sargent & Lundy study’s range. At an estimated annual capital charge rate of 14.3 percent, the carrying cost of an estimated $100 per kW investment would be $14.30 per kW-year. For a coal-fired EGU with a heat rate of 10,450 Btu per kWh, a utilization rate of 78 percent, and a coal price of $2.62 per MMBtu, a six percent heat rate improvement would produce fuel cost savings of approximately $11.20 per kW-year,\textsuperscript{110} leaving approximately $3.10 per kW-year of carrying cost not recovered through fuel cost savings. At an average CO\textsubscript{2} emission rate of 0.976 metric tons per MWh, the same six percent heat rate improvement would reduce CO\textsubscript{2} emissions by 0.40 metric tons per

\textsuperscript{110} 10,450 Btu/kWh * 8760 hours/year * 78% utilization * $2.62 per MMBtu * 6% improvement * 0.000001 MMBtu/Btu = $11.2 per kW-year. Data inputs for average coal-fired EGU heat rate, average coal-fired EGU utilization, and average coal price are from the IPM 5.13 base case for 2020.
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. On the other hand, if an average heat rate improvement of four percent could be achieved for an average investment of $50 per kW, reflecting an assumption that the first improvements pursued would be the least expensive ones, the average cost of CO₂ reductions would fall to $5.81 per metric ton.

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

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111 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.

112 $7.75 per metric ton of CO₂ * 6% / 4% = $11.63 per metric ton of CO₂.

113 $11.63 per metric ton of CO₂ * $50 / $100 = $5.81 per metric ton of CO₂.
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 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, and that the net costs of heat rate improvements as an approach to reducing CO₂ emissions from existing fossil fuel-fired EGUs are reasonable.

Based on the analyses of technical potential and cost summarized above, we propose to find that a six percent reduction in the 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 implemented at a reasonable cost.¹¹⁴

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

¹¹⁴ We note that although we expect that heat rate improvements are also available from other fossil fuel-fired EGUs, because we 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.
on increasing the estimates of the amounts of heat rate improvement achievable through adoption of best practices for operation and maintenance and through equipment upgrades up to six percent and four percent, respectively, particularly in light of the reasonable cost of heat rate improvements. We also solicit comment on the quantitative impacts on the net heat rates of coal-fired steam EGUs of operation at loads less than the rated maximum unit loads.

**d. Assessment of heat rate improvement opportunities at gas- and oil-fired steam EGUs and NGCC units**

The EPA also assessed opportunities to improve heat rates at affected EGUs other than coal-fired steam units. This assessment, which is documented in a Technical Memorandum included as an appendix to the GHG Abatement Measures TSD, considers the potential extent of heat rate improvements and CO₂ reductions that could be reasonably available from oil/gas-fired steam EGUs, NGCC units, and combustion turbine units. For these non-coal technologies, the EPA concludes that the total additional potential CO₂ reductions are very small compared to the potential CO₂ reductions achievable at coal-fired steam EGUs. For this reason, the EPA does not propose to include heat rate improvement opportunities at oil/gas-fired steam EGUs or NGCC units as an element of the BSER for CO₂ emissions from affected
EGUs. However, the EPA expects that for some individual oil/gas-fired steam EGUs, NGCC units, and combustion turbine units, attractive heat rate improvement opportunities will exist. We note that under the proposed flexible approach to state plans described later in this preamble, CO₂ reductions achieved through such opportunities could be used to help meet state goals.

2. Building block 2 – dispatch changes among affected EGUs

The second element of the foundation for EPA’s BSER determination for reducing CO₂ emissions at affected fossil fuel-fired EGUs goes to the achievement of reductions in mass emissions at certain affected EGUs—in particular, fossil fuel-fired steam EGUs—and entails an analysis of the extent to which generation at the most carbon-intensive affected EGUs—again, in particular, fossil fuel-fired steam EGUs—can be replaced with generation at less carbon-intensive affected fossil fuel-fired EGUs—in particular, NGCC units that were in operation or had commenced construction as of January 8, 2014, and are therefore affected units for purposes of this rule.

a. Ability of re-dispatch to reduce CO₂ emissions

The nation’s EGUs are interconnected by transmission grids extending over large regions. EGU owners and grid operators, subject to various reliability and operational constraints, use the flexibility provided by these interconnections to prioritize
among available EGUs when deciding which units should be called upon (i.e., “dispatched”) to increase or decrease generation in order to meet electricity demand at any point in time. Treating increments of generation as to some extent interchangeable, dispatch decisions are based on electricity demand at a given point in time, the variable costs of available generating resources, and system constraints. 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. 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. Operators of EGUs subject to CO₂ emissions limits in RGGI have also relied on replacing generation at higher-emitting EGUs with generation from lower-emitting sources to reduce emissions at the former. Reducing or limiting emissions at high carbon-intensity EGUs by replacing generation at those EGUs with generation at less carbon-
intensive EGUs clearly has the technical capability to reduce overall power sector CO₂ emissions.

We have also analyzed potential upstream net methane emissions impact from natural gas and coal for the impacts analysis. This analysis indicated that any net impacts from methane emissions are likely to be small compared to the CO₂ emissions reduction impacts of shifting power generation from coal-fired steam EGUs to NGCC units. Further information on our analysis of upstream impacts can be found in the Appendix 3A of the RIA.

b. Magnitude of re-dispatch

Having identified replacing generation at higher-emitting EGUs with generation at lower-emitting EGUS as a technically feasible CO₂ emissions reduction strategy, we turn in our BSER determination to the quantity of replacement generation that may be relied upon at reasonable costs. The U.S. electric generating fleet includes EGUs employing a variety of generating technologies. EGUs using technologies with relatively low variable costs, such as nuclear units, are for economic reasons generally operated at their maximum output whenever they are available. Renewable EGUs such as wind and solar units also have low variable costs, but in any event are generally operated when wind and sun conditions permit rather than at operators’
discretion. In contrast, fossil fuel-fired EGUs have higher variable costs and are also relatively flexible. Fossil fuel-fired EGUs are therefore generally the units that operators use to respond to intra-day and intra-week changes in demand.

Because of these typical characteristics of the various EGU types, the primary re-dispatch opportunities among existing units available to EGU owners and grid operators generally consist of opportunities to shift generation among various fossil fuel-fired units, in particular between coal-fired EGUs (as well as oil- and gas-fired steam EGUs) and NGCC units. In the 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{115}

We also researched historical data to determine the utilization rates that NGCC units have already been demonstrated capable of sustaining. Over the last several years, EGU owners and grid operators have engaged in considerable re-dispatch among various types of fossil fuel-fired units relative to historical dispatch patterns, with NGCC units increasing generation and many coal-fired EGUs reducing generation. In fact, in April 2012, for the first time ever the total quantity of electricity generated nationwide from natural gas was approximately equal to the total quantity of electricity

generated nationwide from coal. These changes in generation patterns have been driven largely by changes over time in the relative prices of natural gas and coal, in addition to lower overall demand for electricity. Although the relative fuel prices vary by location, as do the recent patterns of re-dispatch, this trend holds across broad regions of the U.S. In aggregate the historical data provide ample evidence indicating that, on average, existing NGCC units can achieve and sustain utilization rates higher than their present utilization rates.

The experience of relatively heavily used NGCC units provides an additional indication of the degree of increase in average NGCC unit utilization that is technically feasible. According to the historical NGCC unit utilization rate data reported to the EPA, in 2012 roughly 10 percent of existing NGCC units operated at annual utilization rates of 70 percent or higher. 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

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117 The corresponding percentages of NGCC units that in 2012 operated at annual utilization rates of at least 65 percent and at least 75 percent were 16 percent and 6 percent, respectively.
high cyclical demand. For example, on a seasonal basis, a significant number of NGCC units have achieved utilization rates between 50 and 80 percent over the 2012 winter season (December 2011-February 2012) and summer season (June-August 2012), about 16 percent and 19 percent of NGCC units, respectively, operated at utilization rates of 70 percent or more across these entire seasons. 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.

For purposes of establishing state goals, historical (2012) electric generation data was used to apply each building block and develop each state’s goal (expressed as an adjusted CO₂

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119 Air Markets Program Data (at http://ampd.epa.gov/ampd/).
In 2012, electric generation from existing NGCC units was 959 TWh. After the application of NGCC re-dispatch toward a 70 percent target utilization rate, these existing sources were calculated to collectively generate 1,390 TWh. Adding in the existing sources that were under construction in 2012 but not yet in operation increases total NGCC generation calculated in the goal setting to 1,443 TWh.

Although states may choose to comply with state goals through a variety of abatement measures and achieving upwards of 1,400 TWh of NGCC generation in 2020 is therefore not actually required, the EPA nevertheless believes that producing this quantity of generation is feasible for this set of NGCC units. As a reference point, NGCC generation increased by approximately 430 TWh (an 80% increase) between 2005 and 2012. The EPA calculates that NGCC generation in 2020 could increase by approximately 50 percent from today’s levels. This reflects a smaller ramp rate in NGCC generation than has been observed from 2005 to 2012. We also regard these changes as not impairing power system reliability. As we note in the TSD on Resource Adequacy and Reliability, the level of potential re-dispatch can be accommodated within the flexible compliance requirements of

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120 See section VII for further explanation of how goals were computed.
121 For covered sources.
the rule. Similar conclusions have been reached in recent studies of the potential impact of emissions reduction from existing power plants.122

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).123 Fleet-wide combined-cycle average


monthly utilization rates have reached 65 percent, showing that the pipeline system can currently support these rates for an extended period. If the current pipeline and transmission systems allow these utilization rates to be achieved in peak hours and for extended periods, it is reasonable to expect that similar utilization rates should also be possible in other hours when constraints are typically less severe, and be reliably sustained for other months of the year. The second consideration supporting our view that 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 consideration supporting a conclusion regarding the adequacy of infrastructure is that pipeline and transmission planners have repeatedly demonstrated the ability


EIA, Electric Power Monthly, February, 2014. Table 6.7.A.
Natural gas pipeline capacity is regularly added in response to increased gas demand and supply, such as the addition of large amounts of new NGCC capacity in 2001 to 2003, or the delivery to market of unconventional gas supplies since 2008. These pipeline capacity increases have added significant deliverability to the natural gas pipeline network to meet the potential demands from increased use of existing NGCCs. Over a longer time period, much more significant pipeline expansion is possible. In previous studies, when the pipeline system was expected to face very large demands for natural gas use by electric utilities about ten years ago, increases of up to 30 percent in total deliverability out of the pipeline system were judged to be possible by the pipeline industry. There have also been notable capacity expansions over the past five years, in response to increased natural gas supply estimates and advances in drilling techniques. Further, as discussed below in section


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

127 Energy Information Administration, http://www.eia.gov/naturalgas/data.cfm
VII.D on state flexibilities and section VIII on state plans, we believe the flexible nature of the goals provides time for infrastructure improvements to occur should they prove necessary in some locations.\textsuperscript{128} Combining these factors of currently observed utilization rates of up to 65 percent on a monthly basis and time flexibility to address existing infrastructure limitations, it is reasonable to conclude that the natural gas supply system can reliably deliver sufficient supplies to allow average annual NGCC utilization rates of 65 percent, and, given the flexible compliance potential, to move beyond this level to 70 percent utilization rates.

We recognize that re-dispatch does contemplate an associated increase in natural gas production. The EPA expects the growth in NGCC generation assumed in goal setting to be feasible and consistent with domestic natural supplies. Increases in the natural gas resource base have led to fundamental changes in the outlook for natural gas. There is general agreement that recoverable natural gas resources will be substantially higher for the foreseeable future than previously anticipated, exerting downward pressure on natural gas prices.

\textsuperscript{128} See section VII.D and section VIII below for discussion of timing flexibility.
According to EIA, natural gas proved reserves have doubled between 2000 and 2012. Domestic production has increased by 32 percent over that same timeframe (from 19.2 TCF to 25.3 TCF). EIA’s Annual Energy Outlook for 2014 projects that production will further increase to 29.1 TCF, as a result of increased supplies and favorable market conditions. For comparison, NGCC generation growth of 450 TWh (calculated in goal setting) would result in increased gas consumption of roughly 3.5 TCF for the electricity sector.

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

As described in more detail below, the EPA used IPM to assess the costs of requiring increasing levels of re-dispatch from higher- to lower-emitting EGUs, and to that end, EPA developed a series of modeling scenarios that explored shifting generation from existing coal-fired EGUs to existing NGCC units on a 1:1 basis within defined areas.¹²⁹ By the nature of IPM’s design, those scenarios necessarily also require compliance with the constraints just described (as implemented for any specific scenario). IPM was able to arrive at a solution for scenarios reflecting average NGCC utilization rates of 65, 70, and 75 percent, while observing the market, technical, and regulatory constraints embedded in the model. Such a result is consistent

¹²⁹ See Chapter 3 of the Regulatory Impact Analysis for more detail.
with EPA’s determination that increasing the utilization rates of existing NGCC units to 70 percent, not in every individual instance but on average, as part of a comprehensive approach to reducing CO₂ emissions from existing high carbon-intensity EGUs, would be technically feasible.

c. Cost of re-dispatch

Having established the technical feasibility and quantification of replacing incremental generation at higher-emitting EGUs with generation at NGCC facilities as a CO₂ emissions reduction strategy, we next turn in our BSER determination to the question of cost. 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 first set was a dispatch-only set that provided a framework for understanding the broader economic and emissions implications of shifting generation to NGCC units from more carbon-intensive EGUs without consideration of emission reduction measures reflected in the other building blocks. The second set included additional refinements and more closely reflected all the characteristics of the proposed goals that were used as the basis for assessing the costs and benefits of the overall proposal.130 Both sets of analyses were conducted using IPM.

The first set— the dispatch-only analyses— explored the magnitude and cost of potential opportunities to shift generation from existing coal-fired EGUs to existing NGCC units within defined areas. The purpose of analyzing these scenarios was to understand and demonstrate to what extent existing NGCC units could increase their dispatch cost-effectively and without significant impacts on other economic variables such as the prices of natural gas and electricity. To evaluate how EGU owners and grid operators could respond to a state plan’s

130 See Regulatory Impact Analysis for more detail.
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 at least 65, 70, and 75 percent, respectively. For each scenario, we identified the set of dispatch decisions that would meet electricity demand at the lowest total cost, subject to all other specified operating and reliability constraints for the scenario, including the specified constraints and requiring re-dispatch to occur exclusively within a region’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, comparison to the business-as-usual case indicates that the average cost of the CO₂ reductions achieved

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131 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.

132 The costs and economic impacts of the various scenarios were evaluated by comparing the total costs and emissions from each scenario to the costs and emissions from a business-as-usual scenario. For the scenario reflecting a 70 percent NGCC utilization rate, comparison to the business-as-usual case indicates that the average cost of the CO₂ reductions achieved

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To best reflect the integrated nature of the electric power sector EPA defined six regions for this analysis, the borders of which are informed by North American Electric Reliability (NERC) regions and Regional Transmission Organizations (RTOs). See Chapter 3 of the Regulatory Impact Analysis for more detail.
over the 2020-2029 period was $30 per metric ton of CO₂.\textsuperscript{133} 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. One reason for this is that the 70 percent utilization rate in the scenario exaggerates the stringency with which building block 2 is actually reflected in the state goals: while the goal computation procedure uses 70 percent as a target NGCC utilization rate for all states, for only 29 states do the goals actually reflect reaching that target NGCC utilization, with the result that the average NGCC utilization rate reflected in the computed state goals is only 64 percent.\textsuperscript{134} Also, at least some states may be able to achieve additional emission reductions through other components of the BSER, and those other components may be relatively inexpensive. The dispatch-only analyses were focused on evaluating the

\textsuperscript{133} The analogous costs for the scenarios with 65 and 75 percent NGCC utilization rates were $21 and $40 per metric ton of CO₂, respectively.  
\textsuperscript{134} For further explanation of the state goal computation methodology, see section VII of the preamble and the Goal Computation TSD.
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 limited by state boundaries. In these scenarios with less re-dispatch flexibility, the cost of achieving the quantity of CO₂ reductions corresponding to a nationwide average NGCC unit utilization of 70% was $33 per metric ton. Combining the results of the modeling with the factors likely to be present in the real world reinforces the support we expressed above for the 70 percent utilization rate. We remain concerned, however, that higher NGCC utilization rates could be harder to sustain and could exert further upward pressure on prices.

We invite comment on whether the regional or state scenarios should be given greater weight in establishing the
appropriate degree of re-dispatch to incorporate into the state goals for CO₂ emission reductions, and in assessing costs.

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 both of the 70 percent NGCC unit utilization rate scenarios — with re-dispatch limited to regional and state boundaries, respectively — delivered natural gas prices were projected to increase by an average of no more than ten percent over the 2020-2029 period, which is well within the range of historical natural gas price variability.¹³⁵ Projected wholesale electricity price increases over the same period were less than seven percent in both cases, which similarly is well within the range of historical electric price variability.¹³⁶ 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.

¹³⁶ For example, year-on-year changes in PJM wholesale electricity prices averaged 19.5 percent over the period from 2000 to 2013. Ventyx Velocity Suite, ISO real-time data for all hours. Price variability for other eastern ISO regions (NYISO, ISO-NE, and Midcontinent ISO) was similar. Id.
However, for the same reasons discussed above with respect to estimated costs per ton of CO₂, in actual implementation we again expect that the economic impacts shown in these scenarios, including natural gas price impacts, are overstated compared to the impacts that would actually occur in real-world compliance with this rule’s proposed goals. Consistent with this expectation, the comprehensive analyses used to assess the compliance costs and benefits of this proposal, which reflect a more complete representation of the additional flexibility available to states, show significantly smaller economic impacts. These analyses are discussed 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 mass emission reductions achievable at fossil fuel-fired steam EGUs can be determined by the degree of re-dispatch that can be implemented at reasonable cost such that electricity generation could be shifted from more carbon-intensive EGUs to less carbon-intensive EGUs within the state. The increment of emission reductions incorporated in this component of our proposed BSER determination is commensurate with an annual utilization rate for the state’s NGCC units of up to the point at which 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.
to 70 percent, on average across all the NGCC units in the state.

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

We also specifically invite comment on raising the NGCC utilization rate target to a level higher than 70 percent, and in particular 75 percent. As noted above, six percent of NGCC plants operated at or above a 75 percent utilization rate in 2012.137

137 For further analysis related to the use of a 75 percent target utilization rate for NGCC units, see chapter 3 of the GHG Abatement Measures TSD.
We invite comment on these proposed findings and on all other issues raised by the discussion above and the related portions of the Greenhouse Gas Abatement Measures TSD.

3. Building block 3 – using an expanded amount of less carbon-intensive generating capacity

The third element of the foundation for EPA’s BSER determination for reducing CO₂ emissions at affected fossil fuel-fired EGUs also goes to the achievement of reductions in mass emissions, but in this case the reductions would occur at all affected EGUs, and entails an analysis of the extent to which generation at the affected EGUs can be replaced by using an expanded amount of lower-carbon generating capacity to produce replacement generation. Below we discuss two types of generating capacity that can play this role: renewable generating capacity, and new and preserved nuclear capacity.

a. Renewable generating capacity

Renewable electricity (RE) generating technologies are a well-established part of the U.S. power sector. In 2012, electricity generated from renewable technologies, including conventional hydropower, represented 12 percent of total U.S. electricity generation, up from 9 percent in 2005. More than half the states have established renewable portfolio standards (RPS) that require minimum proportions of electricity sales to
be supplied with generation from renewable generating resources.  

Production of this renewable generation displaces predominantly fossil fuel-fired generation and thereby avoids the CO₂ emissions from that displaced generation. EPA believes that renewable electricity generation is a proven way for states to reduce CO₂ emissions at affected EGUs at a reasonable cost.  

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

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140 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.

141 Given their unique locations, Alaska and Hawaii are not grouped with other states into these regions. As a conservative
comparing each state to a set of neighbors rather than to a single national standard, we are able to take regional variation into account while still maintaining a level of rigor for the scenario’s targets. The regional structure is informed by North American Electric Reliability Corporation (NERC) regions and Regional Transmission Organizations (RTOs), with adjustments to align regional borders with state borders and to group Florida and Texas with neighboring states. This structure accounts for similar power system characteristics as well as geographic similarities in RE potential. The grouping of states into the six regions is shown in Table 3 below.

Table 3: Regions for Development of Best Practices RPS Scenario

<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,</td>
</tr>
</tbody>
</table>

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.

142 The regions are the same as those used in regional modeling of this rule; see the Regulatory Impact Analysis for more information on the regional modeling.
<table>
<thead>
<tr>
<th>Region</th>
<th>States</th>
</tr>
</thead>
<tbody>
<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.

The best practices scenario for each state consists of growing annual levels of RE generation, estimated based on application of an annual RE growth factor to the state’s historical RE generation, subject to a maximum RE generation target. The annual RE growth factors and maximum RE generation targets were developed separately for each of the six regions. Our procedure for determining these elements is described in the Greenhouse Gas Abatement Measures TSD and summarized below.
The EPA first quantified the amount of renewable generation in 2012 in each state. 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. **Most hydropower generation is excluded from this existing 2012 generation for purposes of quantifying BSER-related RE generation potential because state RPS requirements typically exclude the historical output at pre-existing hydropower facilities from qualifying. Additionally, building the methodology from a baseline that includes large amounts of existing hydropower generation could distort goals for states with large amounts of existing hydropower capacity as well as for their regional neighbors lacking that existing capacity. (The exclusion of pre-existing hydropower generation from the baseline of this goal-setting framework does not exclude it as an option for state compliance.)**

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
generation for the region. We also computed each state’s maximum
RE generation target in the best practices scenario as its own
2012 generation multiplied by that average percentage. (For some
states that already have RPS requirements in place, these
amounts are less than their RPS targets for 2030.)

For each region we then computed the regional growth factor
necessary to increase regional RE generation from the regional
starting level to the regional target through investment in new
RE capacity, assuming that the new investment begins in 2017,
the year following the initial state plan submission deadline,\textsuperscript{144}
and continues through 2029. This regional growth factor is the
growth factor used for each state in that region to develop the
best practices scenario.

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

\textsuperscript{144} See Section VIII below for further discussion of timing
requirements for state plan submittals.
computation of the alternate state goals discussed in section VII.E below on which we are seeking comment, we used the annual amounts for the years 2020 through 2024.

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

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

The cumulative RE amounts for each state, represented as percentages of total generation, are shown in Table 4.

Table 4: State RE Generation Levels for State Goal Development (Percentage of Annual Generation)\\n
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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.

The EPA believes that RE generation at the levels represented in the best practices scenario can be achieved at

**Deleted:** Several studies have found the cost
reasonable costs. According to an EPA analysis based on EIA levelized costs, the cost to displace emissions through RE ranges from $10 to $40 per metric ton of CO₂. ¹⁴⁶ Analysis of RE development in response to state RPS policies also finds historical and projected costs of RPS-driven RE deployment to be modest. One comparative analysis that "synthesize[d] and analyze[d] the results and methodologies of 28 distinct state or utility-level RPS cost impact analyses" projected the median change in retail electricity price to be $0.0004 per kilowatt-hour (a 0.7 percent increase), the median monthly bill impact to be between $0.13 and $0.82, and the median CO₂ reduction cost to be $3 per metric ton. ¹⁴⁷ 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. ¹⁴⁸

¹⁴⁶ This analysis is based upon EIA’s AEO 2014 Estimated Levelized Costs of Electricity for New Generation Sources, available at http://www.eia.gov/forecasts/aeo/electricity_generation.cfm.
Additionally, the National Renewable Energy Laboratory has projected low incremental costs for a range of scenarios reflecting significant increases in RE penetration, including scenarios that increase RE penetration to a range of 30 to 40 percent of national generation, levels higher than those projected in our best practices scenario.\textsuperscript{149}

While RPS requirements will continue to grow over time, EPA does not expect this anticipated expansion to fall outside the historical norms of deployment, or to create unusual pressure for cost increases. Full compliance with current RPS goals through 2035 would require approximately 4 to 4.5 GW of new renewable capacity per year. Average deployment of RPS-supported renewable capacity from 2007–2012 has exceeded 6 GW per year.\textsuperscript{150} 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.\footnote{151}

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

\[\text{[PLACEHOLDER FOR SOLICITATION OF COMMENT ON AN ALTERNATIVE METHOD OF QUANTIFYING BSER RE GENERATION THAT IS CURRENTLY UNDER DEVELOPMENT WITH INTERAGENCY REVIEWERS]}\]

b. New and preserved nuclear capacity

Nuclear generating capacity facilitates CO₂ 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 CO₂ emissions from affected fossil fuel-fired EGUs.

\footnote{151} \url{http://emp.lbl.gov/rps}, retrieved March 2014. The RPS compliance measure cited is inclusive of credit multipliers and banked RECs utilized for compliance, but excludes alternative compliance payments, borrowed RECs, deferred obligations, and excess compliance. This estimate does not represent official compliance statistics, which vary in methodology by state.
One way to increase the amount of available nuclear capacity is to build new nuclear EGUs. However, in addition to having low variable operating costs, nuclear generating capacity is also relatively expensive to build compared to other types of generating capacity, and little new nuclear capacity has been constructed in the U.S. in recent years; instead, most recent generating capacity additions have consisted of NGCC or renewable capacity. Nevertheless, five 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 (although EPA acknowledges that the planning for those units likely included consideration of the possibility of future regulation of CO2 emissions from EGUs). 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 as a result of 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. However, the EPA also realizes that reflecting completion of these units in the goals has a significant impact on the calculated goals for the states in which these units are located. If one or more of the units were not completed as projected, that could have a significant impact on the state’s ability to meet the goal. We therefore take comment on whether it is appropriate to reflect completion of these units in the state goals and on alternative ways of considering these units when setting state goals.

Another way to increase the amount of available nuclear capacity is to preserve existing nuclear EGUs that might otherwise be retired. The EPA is aware of six nuclear EGUs at five plants that have retired or whose retirements have been announced since 2012: San Onofre Units 2-3 in California, Crystal River 3 in Florida, Kewaunee in Wisconsin, Vermont Yankee in Vermont, and Oyster Creek in New Jersey. While each retirement decision is based on the unique circumstances of that individual unit, the EPA recognizes that a host of factors – increasing fixed operation and maintenance costs, relatively low wholesale electricity prices, and additional capital investment associated with ensuring plant security and emergency preparedness – have altered the outlook for the U.S. nuclear
fleet in recent years. Reflecting similar concern for these challenges, EIA in its most recent Annual Energy Outlook has projected an additional 5.7 GW of capacity reductions in the existing nuclear fleet. EIA describes the projected capacity reductions – which are not tied to the projected retirement of any specific unit – as necessary to recognize the “continued economic challenges” faced by the higher-cost nuclear units.\(^{152}\)

Likewise, without making any judgment about the likelihood that any individual EGU will retire, we view this 5.7 GW, which comprises an approximately six percent share of nuclear capacity, as a reasonable proxy for the amount of nuclear capacity at risk of retirement.

We have determined 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 CO\(_2\) reductions from affected EGUs. For example, retaining the estimated seven percent of at-risk nuclear capacity could avoid 200 to 300 million metric tons of CO\(_2\) over an initial compliance phase-in period of ten years.\(^{154}\)

\(^{152}\) Jeffrey Jones and Michael Leff, EIA, “Implications of accelerated power plant retirements,” (April 2014).

\(^{154}\) Assuming replacement power for at-risk nuclear capacity is sourced from new NGCC capacity at 800 lbs/MWh or the power
to a recent report, 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 at-risk nuclear capacity, one can estimate the value of offsetting the revenue loss at these at-risk nuclear units to be approximately $12 to $17 per metric ton. EPA views this cost as reasonable. We therefore propose that the emission reductions achievable by retaining in operation six 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.

System at 1127 lbs CO₂/MWh (average 2020 power sector emissions intensity as projected in EPA’s IPM Base Case).

“Nuclear... The Middle Age Dilemma?” Eggers, et al., Credit Suisse, February 2013
We invite comment on all aspects of the approach discussed above. In addition, we specifically request comment on whether we should include in the state goals an estimated amount of additional nuclear capacity whose construction is sufficiently likely to merit evaluation for potential inclusion in the goal-setting computation.

4. Building block 4 — demand-side energy efficiency

The fourth element of the foundation for EPA’s BSER determination for reducing CO₂ emissions at affected fossil fuel-fired EGUs also reduces mass emissions at all affected EGUs, and entails an analysis of the extent to which generation at the affected EGUs can be reduced by reducing the demand for generation at those EGUs through measures that reduce the overall quantity of generation demanded by end-users.¹⁵⁸

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. Every state has established demand-side energy efficiency policies, and many

¹⁵⁸ Electricity end-users and electricity end-use referred to throughout this section includes the residential, commercial and industrial sectors.
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.\textsuperscript{159} Additionally, multiple studies have found that significant improvements in end-use energy efficiency can be realized at less cost than the savings from avoided power system costs.\textsuperscript{160}

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 CO\textsubscript{2} emissions.


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.¹⁶¹ And when integrated into a comprehensive approach for addressing CO₂ 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 CO₂ emissions. In addition to reducing the CO₂ emissions and carbon intensity of the power sector, because it drives reductions in fossil fuel usage at EGUs, demand-side energy efficiency also reduces criteria pollutant emissions, cooling water intake and discharge, and solid waste production associated with fossil fuel combustion. By reducing electricity

usage significantly, energy efficiency also commonly reduces the bills of electricity customers.

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

To estimate the potential CO₂ 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 represents a feasible policy scenario showing the reductions in fossil fuel-fired electricity generation resulting from accelerated use of energy efficiency policies in all states consistent with a level of performance that has already been achieved or required by policies (e.g., energy efficiency resource standards) of the leading states. The data and methodology used to develop the best practices scenario are summarized below.
We have not assumed any particular type of demand-side energy efficiency policy. States with leading energy efficiency performance have employed a variety of strategies that are implemented by a range of entities including investor-owned, municipal and cooperative electric utilities as well as state agencies and third-party administrators. These include energy efficiency programs, building energy codes, state appliance standards (for appliances without federal standards), tax credits, and benchmarking requirements for building energy use. Energy efficiency policies are designed to accelerate the deployment of demand-side energy efficiency technologies, practices, and measures by addressing market barriers and market

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

163 See the Existing State Actions TSD for descriptions of the full array of demand-side energy efficiency policies currently employed by states.
failures that limit their adoption. Some states have adopted energy efficiency resource standards\(^{164}\) (EERS) to drive investment in energy efficiency programs; some have relied on other strategies: most states are using multiple policy approaches. Based on historical data on energy efficiency program savings and analysis of the requirements of existing state energy efficiency policies, twelve leading states have either achieved – or have established requirements that will lead them to achieve – annual incremental savings rates of at least 1.5 percent of the electricity demand that would otherwise have occurred.\(^{165}\) The 1.5 percent savings rate is inclusive of, not additional to, existing state energy efficiency requirements. These savings levels are realized exclusively through the adoption and implementation of energy efficiency programs. The energy savings data underpinning these analyses are derived from energy efficiency program reports required by

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\(^{164}\) 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.

\(^{165}\) The historical data used are reported to the Energy Information Administration through Form EIA-861. The analysis and summary of state energy efficiency policies is from the American Council for an Energy-Efficient Economy (ACEEE), State EERS Activity Policy Brief (February 24, 2014). See the Greenhouse Gas Abatement Measures TSD for more information.
state public utility commissions and other entities with a similar oversight role.\textsuperscript{166} 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.\textsuperscript{167}

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\textsuperscript{168} rate to be a reasonable estimate of the energy efficiency policy

\textsuperscript{166} E.g., energy efficiency programs operated by municipal and cooperative utilities may report their program results to their Boards of Directors rather than to a state utility commission.

\textsuperscript{167} See the EM&V section of the state Plan TSD for more information on EE program evaluation.

\textsuperscript{168} This incremental savings rate and all others discussed in this section represent net, rather than gross, energy savings. Gross savings are the changes in energy use (MWh) that result directly from program-related actions taken by program participants, regardless of why they participated in a program. Net savings refer to the changes in energy use that are directly attributable to a particular energy efficiency program after accounting for free-ridership, spillover, and other factors.
performance that is already achieved or required by leading states and that can be achieved cost-effectively by all states given adequate time. If we were to capture the potential for additional policies, such as the adoption and enforcement of state or local building energy codes, to contribute additional reductions in electricity demand beyond those resulting from energy efficiency programs, we could reasonably increase the targeted annual incremental savings rate beyond 1.5 percent.

For states 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\textsuperscript{169} 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 incremental savings rate can expand its energy efficiency programs to reach that rate sooner 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

\textsuperscript{169} 2012 is the most recent year for energy efficiency program incremental savings data reported using EIA Form 861.
past performance and future requirements of leading states.\textsuperscript{170} For states already at or above the 1.5 percent annual incremental savings rate,\textsuperscript{170} we estimate that they would realize a 1.5 percent rate in 2017 and maintain that rate through 2029. For all states we assume the initial savings rate (the lower of their 2012 value or 1.5 percent) is realized in 2017 and increases each year by 0.2 percent until the target rate of 1.5 percent is achieved\textsuperscript{171} and is then maintained at that level through 2029. The 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

\textsuperscript{170} See the Greenhouse Gas Abatement Measures TSD for more information.

\textsuperscript{171} For example, a state with a reported savings rate of 0.5\% in 2012 is assumed to realize a 2017 savings rate of 0.5\% and their savings rates for 2018, 2019, 2020, 2021 and 2022 are calculated to be 0.7\%, 0.9\%, 1.1\%, 1.3\%, and 1.5\%, respectively. By this method, all states have reached the 1.5\% target rate by 2017 at the earliest and by 2025 at the latest.
would be achieved for the period 2020 to 2029 based on the state’s reaching and then sustaining the best practices annual incremental savings rate through 2029. These values, for each state and for each year (2020-2029), are used in the procedure for computing the state goals described in section VII.C below.

As discussed in section VII.E below, the EPA is also taking comment on a less stringent alternative for setting state goals. Under this alternative, the demand-side energy efficiency requirement is 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 historical levels is relaxed slightly to 0.15 percent per year (rather than 0.2 percent). The 1.0 percent rate of savings is a level of performance that has been achieved - or that established state requirements will cause to be achieved - by 20 states.\textsuperscript{173} 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.

\textsuperscript{173} See the Greenhouse Gas Abatement Measures TSD for more information.
The state-specific cumulative annual electricity saving data inputs for both the proposed approach and the less stringent alternative are discussed in the Greenhouse Gas Abatement Measures TSD and summarized in Table 5.

<table>
<thead>
<tr>
<th>State</th>
<th>1.5% Savings Target Scenario</th>
<th>1.0% Savings Target Scenario</th>
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<tr>
<td></td>
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</tr>
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<td>11.6%</td>
</tr>
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</table>

174 Vermont and the District of Columbia are excluded from this table because we are not proposing goals for those jurisdictions.
<table>
<thead>
<tr>
<th>State</th>
<th>Percent 1</th>
<th>Percent 2</th>
<th>Percent 3</th>
<th>Percent 4</th>
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</tr>
</tbody>
</table>
c. Costs of demand-side energy efficiency

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

The processes by which states develop funding for energy efficiency programs typically require the application of cost-effectiveness tests to ensure that adopted program portfolios lead to lower costs than the use of generation sources that would otherwise be required to meet the associated electricity
service demands. Indeed, a major reason for the widespread presence and rapid growth of demand-side energy efficiency programs is the strong evidence of their cost-effectiveness even before the additional benefit of CO₂ reductions is considered.\textsuperscript{175} Independent studies have found that end-users’ needs for energy-dependent services (e.g., heating, cooling, lighting, motor output, and information and entertainment services) frequently can be satisfied at lower cost by improving the efficiency of electricity consumption rather than by increasing the supply of electricity.\textsuperscript{176} These factors indicate that the cost of CO₂ reductions achieved through implementation of demand-side energy efficiency at the levels reflected in the best practices scenario are likely to be very reasonable, typically resulting in reductions in average electricity bills across all end-use sectors.\textsuperscript{177}

\textsuperscript{175} Some states do include a valuation of CO₂ benefits as part of their evaluations of cost effectiveness.


\textsuperscript{177} 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

\begin{itemize}
  \item Federal and independent
  \item In our view, the
  \item mentioned above
  \item is
  \item low and may even be less than $0 per metric ton
  \item Assessment of Achievable Potential from
\end{itemize}
Another approach to evaluating the reasonableness of the costs associated with this building block is to compare the demand-side energy efficiency costs to the avoided power system costs as represented within the EPA’s modeling of the power sector. The costs associated with the best practices scenario were estimated based upon a synthesis of data and analysis of the factors that impact energy efficiency program costs as calculated using an engineering-based, bottom-up approach that is standard for state and utility analysis of these policies. These factors include the average energy efficiency program costs per unit of first-year energy savings ($/MWh), the ratio of program to participant costs, and the lifetimes of energy efficiency measures across the full portfolio of programs. In addition, EPA has included a cost escalation factor to represent the possibility of increased costs associated with higher levels of incremental energy savings rates and the national scope of the best practices scenario. EPA has taken a conservative approach to each of these factors, selecting values that are at the higher-cost end of reasonable ranges of estimated values. The combination of these factors is reflected in the value EPA 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.
has derived for the levelized cost per MWh of saved energy. This value includes both the program costs paid by utilities for implementing energy efficiency programs and the amounts that program participants pay for their own energy efficiency improvements beyond the program costs. These costs are levelized across the measure lifetimes of a full portfolio of energy efficiency programs. This analysis provides a levelized cost of saved energy (LCOSE) range of $85/MWh to $90/MWh ($2011) over the 2020 to 2030 period. This range of LCOSE is notably conservative (leading to higher costs) in comparison with most utility and state analysis. For example, a 2014 analysis by the American Council for an Energy-Efficient Economy (ACEEE) surveyed program and participant cost results across seven states and found a comparable LCOSE value of $54/MWh (2011$).\(^{180}\)

To estimate the reductions in power system costs and CO\(_2\) emissions associated with the best-practices level of demand-side energy efficiency described above, EPA analyzed a scenario incorporating the resulting reduction in electricity demand and compared the results with the business-as-usual scenario. Both analyses were conducted using the Integrated Planning Model.

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(IPM) described previously. Combining the resulting power system cost reductions with the energy efficiency cost estimates associated with the best practices scenario, EPA derived net cost impacts for 2020, 2025, and 2030. Dividing these net cost impacts by the associated CO₂ reductions for each year, EPA found that the average cost of the CO₂ reductions achieved ranged from $16 to $24 per metric ton of CO₂. EPA views these estimated costs as reasonable. Together with the history of demonstrated successful state implementation of cost-effective demand-side energy efficiency programs discussed above, this analysis supports the reasonableness of the level of demand-side energy efficiency represented by the best practices scenario and, by extension, the reasonableness of the emission reductions at affected EGUs that can be achieved consistent with achievement of that level of demand-side energy efficiency.

Further details regarding the data and methodology used to evaluate the potential for demand-side energy efficiency programs to substitute for generation at affected EGUs and thereby facilitate reductions of power sector CO₂ emissions at reasonable costs are provided in the Greenhouse Gas Abatement Measures TSD. We invite comment on all aspects of our data and methodology as discussed above and in the TSD, as well as on the level of reductions we propose to define as best practices.
suitable for representation consistent with the best system of emission reduction and the level reflected in the less stringent scenario. We also specifically invite comment on several issues: 1) increasing the annual incremental savings rate to 2.0 percent and the pace of improvement to 0.25 percent per year to reflect an estimate of the additional electricity savings achievable from state policies not reflected in the 1.5 percent rate and the 0.20 percent per year pace of improvement, such as building energy codes and state appliance standards, 2) alternative approaches and/or data sources (i.e., other than EIA Form 861) for determining each state’s current level of incremental annual electricity savings, and 3) alternative approaches and/or data sources for evaluating costs associated with implementation of state demand-side energy efficiency policies.

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

There are three 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, carbon capture and storage (CCS), and reducing emissions at affected fossil fuel-fired steam EGUs by
using expanded amounts of less carbon-intensive new NGCC capacity to provide replacement generation.

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 $83 per metric ton to $150 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\textsuperscript{181} technology (CCS). In the recently proposed standards of performance for new fossil fuel-fired EGUs (79 FR 1430), the EPA proposed to find that the best system of emission reduction for new fossil fuel-fired boilers and IGCC units is partial application of CCS. In that proposal, the EPA found that, for new units, partial CCS has been adequately demonstrated; it is technically feasible; it can be implemented at costs that are not unreasonable; it provides meaningful emission reductions; and its implementation will serve to promote further development and deployment of the technology. The EPA also noted in the proposal that most of the relatively few new boiler and IGCC EGU projects currently under development are already planning to implement CCS; and, as a result, the proposed standard would not have a significant impact on nationwide energy prices.

In contrast, the EPA did not identify full or partial CCS as the BSER for new natural gas-fired stationary combustion turbines, noting technical challenges to implementation of CCS at NGCC units as compared to implementation at new solid fossil.

\textsuperscript{181} This is also sometimes referred to as “carbon capture and sequestration.”
fuel-fired sources. The EPA also noted that, because virtually all new fossil fuel-fired power projects are projected to use NGCC technology, requiring full or partial CCS would have a greater impact on the price of electricity than requiring CCS at the few projected coal plants, and the larger number of NGCC projects would make a CCS requirement difficult to implement in the short term.

Partial CCS has been demonstrated at existing EGUs. It has been demonstrated at a pilot-scale at Southern Company’s Plant Barry; it is being installed for large-scale demonstration at NRG’s W.A. Parish facility; and it is expected soon to be applied at commercial-scale as a retrofit at SaskPower’s Boundary Dam plant in Canada. However, the costs of integrating 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.

c. New NGCC capacity

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

182 For purposes of this proposal, NGCC units that have commenced construction as of January 8, 2014 are “existing” units.
regarding the feasibility of policies to increase utilization
rates of existing NGCC units on average to 70 percent applies
equally to new NGCC units. We view the opportunity to reduce
CO₂ emissions at affected EGUs by means of addition and operation
of new NGCC capacity as clearly feasible.

Compared to the opportunity to reduce CO₂ 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 CO₂ 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

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183 Whether and to what extent adding new NGCC capacity is likely
to lead to CO₂ 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 CO₂ emissions.
achieving CO₂ reductions at affected EGUs, some portion of their construction or fixed operating costs might also be attributable 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.

Moreover, 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.

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

This subsection summarizes the EPA’s examination of combinations of the building blocks as components of the BSER, comparing the merits of a potential BSER that is comprised only of building blocks 1 and 2 with the merits of a BSER that is
comprised of all four building blocks - the preferred option in this proposal. (A more detailed discussion of how we evaluated each option against the criteria to be considered the BSER follows in section VI.E.)

1. Reasons for considering combinations of building blocks

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

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

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

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

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

The EPA initially considered a BSER comprised of only strategies within building block 1. As described earlier in
subsection VI.B, the EPA concluded that certain strategies within building block 1 – specifically heat rate improvements at individual coal-fired steam EGUs – should be a component of the BSER determination, as they are technically feasible and can be implemented at a reasonable cost. However, the EPA further concluded that, while heat rate improvements qualify as a system of emission reduction, they are not in themselves the BSER as there are additional strategies that can be utilized in combination with building block 1 that are technically feasible, can be implemented at reasonable cost, and result in greater emission reductions than would be achieved through building block 1 strategies alone. The EPA is also concerned that if the measures that improve heat rates at coal-fired steam EGUs in building block 1 are implemented in isolation, without additional measures that reduce overall electricity demand or encourage substitution of less carbon-intensive generation for more carbon-intensive generation, the resulting increased efficiency of coal-fired steam units would provide incentives to operate those EGUs more, leading to smaller overall reductions in CO₂ emissions. Further, in listening sessions and other outreach meetings, the EPA learned that states and other sources were already implementing and pursuing strategies in the other
building blocks for the purpose, at least in part, of reducing CO₂ emissions.

2. A combination of building blocks 1 and 2 as the Best System of Emission Reduction

   We considered a BSER that is comprised of strategies from building blocks 1 and 2. In this system, emission reductions at the most carbon-intensive individual affected EGUs would occur through a combination of heat rate improvements (resulting in a decrease in emission rates) and substitution of generation at less carbon-intensive affected EGUs, notably existing NGCC units. One reason for considering a BSER comprised of these two building blocks is that it involves only affected EGUs and generation from affected EGUs.

   The EPA believes that the combination of building blocks 1 and 2 would be a “system of emission reduction” capable of achieving significant reductions in CO₂ emissions from affected EGUs at a reasonable cost. As discussed in subsection VI.C above, each of the two building blocks independently would be capable of achieving meaningful CO₂ emission reductions at reasonable costs. In combination, the need to achieve the level of emission reductions achievable through use of building block 2 can mitigate the concern that building block 1, implemented alone, would make coal-fired EGUs more economically competitive.
and lead to increased generation that would offset the emission reduction benefits of the carbon-intensity improvements. While combining the building blocks may also raise the cost per ton of emission reductions achieved through heat rate improvements (by reducing the quantity of MWh generated from the EGUs with improved heat rates and therefore also reducing the aggregate emission reductions achieved at those EGUs by the heat rate improvements), the costs of heat rate improvements are low enough that we believe their cost per ton of emission reduction would remain reasonable.

Nevertheless, the EPA is not proposing that a combination of building blocks 1 and 2 is the BSER, because it fails to encompass the additional measures – building blocks 3 and 4 – that we and stakeholders have identified as already in use and capable of achieving even greater CO₂ emission reductions from affected EGUs at reasonable costs. The state-specific goals that would be computed consistent with a BSER based on the combination of building blocks 1 and 2 (i.e., goals computed using the goal computation methodology discussed in section VII below, except for the omission of building blocks 3 and 4) are presented in the Goal Computation TSD available in the docket. Further information on the EPA’s evaluation of this combination is available in the “Analysis of Emission Reductions, Costs,
Benefits and Economic Impacts Associated with Building Blocks 1 and 2 are available in the docket. We invite comment on a potential BSER comprised of a combination of building blocks 1 and 2.

3. A combination of all four building blocks as the Best System of Emission Reduction

Our proposal for the BSER is a combination of all four building blocks. As discussed in subsection VI.C above, each of the four building blocks is a proven way to support either improvements in emissions rates at affected EGUs or reductions in EGU mass emissions; each is in widespread use and is independently capable of supporting significant CO₂ reductions from affected EGUs, either on an emission rate or mass-emissions basis, at a reasonable cost consistent with ensuring system reliability. As discussed in subsection VI.E below, the emission reductions achievable with the support of the combination of all four building blocks satisfies the legal criteria to be considered the BSER. Further, as discussed in section X below, the combination of all four building blocks can achieve greater overall CO₂ emission reductions from affected EGUs, at a lower cost per unit of CO₂ eliminated, than the combination of building blocks 1 and 2.

In the large and highly integrated electric system, where electricity is fungible and the demand for electricity services
can be met in many ways (including through demand-side energy efficiency), states and the industry have long pursued a wide variety of strategies for ensuring that the demand for electricity services is met reliably, at reasonable costs, and in a manner consistent with evolving constraints, including environmental objectives. These strategies have long extended to the measures in all four building blocks. We believe the combination of all four building blocks fairly represents the range of measures that states and the industry will consider when developing state plans and strategies for reducing CO₂ emissions from affected EGUs while continuing to meet demand for electricity services reliably and affordably. As such, we believe it is appropriate to consider that same combination as the BSER upon which the required CO₂ standards of performance for affected EGUs should be based.

E. Determination of the Best System of Emission Reduction

1. Overview

The EPA is proposing that the measures in the four building blocks described in the preceding subsections are essential features of 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. Specifically, the EPA is proposing alternative formulations for
the BSER. Under one approach, emission rate improvements and mass emission reductions facilitated through the adoption of the four building blocks themselves meet the criteria for the BSER because they will amount to substantial reductions in CO₂ emissions achieved while maintaining fuel diversity and a reliable, affordable electricity supply for the United States. Under an alternate approach, BSER consists of building block 1 coupled with reduced utilization in specified amounts from higher-emitting EGUs. Under this latter approach, the measures in building blocks 2, 3, and 4 serve to justify those amounts and the “adequate[] demonstration” because they are proven measures that are already being pursued by states and the industry, at least in part for the purpose of reducing CO₂ emissions from affected EGUs.

The remainder of this discussion is organized into nine subsections. Subsection 2 contains a summary of relevant considerations for the BSER as defined in the statute and further interpreted in court decisions. Subsection 3 discusses characteristics of the electricity industry relevant to interpretation of the BSER for purposes of this proposal, most notably the industry’s highly interconnected and integrated nature. Subsection 4 provides a discussion of how the building blocks would satisfy the BSER criteria in isolation or support
the alternative formulation of the BSER as including reduced utilization in specified amounts. Subsection 5 evaluates two combinations of building blocks - a combination of building blocks 1 and 2, and the proposed combination of all four building blocks - against the BSER criteria, and explains why we propose that the combination of all four is the BSER. In subsection 6, we describe and seek comment on the alternate interpretation that the BSER includes, in addition to one or more of the building blocks, a component consisting of reduced generation from affected EGUs, with the measures in the other building blocks serving as the basis for quantifying the amounts of generation reductions and consequent CO₂ emission reductions that can be achieved while continuing to meet the demand for electricity services in a reliable and affordable manner. In subsection 7 we discuss the discretion that the case law gives us in weighing the various criteria to determine the BSER. The final three subsections address the topics of combining source categories, severability, and certain other specific issues on which we are seeking comment. Additional discussion is provided in the Legal Memorandum available in the docket.

2. Statutory and regulatory provisions related to determination and application of the BSER
The EPA’s explanation for this BSER proposal begins with the statutory definition of a “standard of performance”:

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

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

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

- The system of emission reduction must be technically feasible.
- The EPA must consider the amount of emission reductions that the system would generate.

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The costs of the system must be reasonable. The EPA may consider costs at the source level, the industry level, and, at least in the case of the power sector, the national level in terms of the overall costs of electricity and the impact on the national economy over time.\textsuperscript{185}

The EPA must also consider that CAA section 111 is designed to promote the development and implementation of technology.

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

\textsuperscript{185} 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, the EPA stated that “these various formulations of the cost standard ... are synonymous,” and, for convenience, we used “reasonableness” as the formulation. We take the same approach in this rulemaking.
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.

3. The interconnected nature of the U.S. electricity sector

The U.S. electricity system is a highly interconnected, integrated system in which large numbers of EGUs using diverse fuels and generating technologies are operated in a coordinated manner to produce fungible electricity services for customers. Because electricity is costly to store, the amounts of electricity demanded and supplied must be continuously matched, and system operators typically have flexibility to choose among multiple EGUs when selecting where to obtain the next MWh of generation needed. Coordination over short- and long-term time scales is accomplished through a variety of institutions including vertically integrated utilities, state regulatory agencies, independent system operators and regional transmission organizations (ISO/RTOs), and market mechanisms. The electricity
sector is both critical to the nation’s economy and the source of more than 30 percent of U.S. greenhouse gas emissions, predominantly in the form of CO₂.

The integrated electricity system allows increased generation from less carbon-intensive NGCC units to substitute for generation from more carbon-intensive steam EGUs (building block 2), thereby lowering CO₂ emissions from the group of affected EGUs as a whole. The electricity system similarly allows increased generation resulting from expansion of the amount of available low- or zero-carbon generating capacity connected to the electric grid (building block 3), as well as avoided generation resulting from reductions in electricity demand (building block 4), to substitute for fossil fuel-fired generation, thereby reducing CO₂ emissions from affected EGUs. Each of these measures already routinely occurs within this integrated system for providing electricity and electricity services.

The integrated nature of the electricity system has long played a central role in the industry’s continuing efforts to assure reliability and to manage costs generally. Specifically in the area of pollution control, state governments and the federal government have repeatedly taken advantage of the integrated nature of the electricity system when designing...
programs to allow the industry to meet the pollution control objectives in a least-cost manner. Examples include several cap-and-trade programs to reduce national or regional emissions of SO$_2$ and NOx: the SO$_2$–related portion of the CAA Title IV Acid Rain Program, the Ozone Transport Commission (OTC) NOx Budget Program, the NOx SIP Call NOx Budget Trading Program, and the Clean Air Interstate Rule (CAIR) annual SO$_2$, annual NOx, and ozone-season NOx trading programs. While the Acid Rain Program was created by federal legislation, the OTC NOx Budget Program was developed primarily through the joint efforts of a group of northeastern states. In the NOx SIP Call and CAIR programs, the federal government set emission budgets and developed trading programs that states could use as a compliance option. Each of these programs was designed to take advantage of the fact that in an integrated electricity system, some EGUs can reduce emissions more cost-effectively than others, and that by allowing the industry to determine through market mechanisms which EGUs to control, and potentially operate more, and which to leave uncontrolled, and potentially operate less, overall compliance costs can be reduced. The integrated electricity

186 In the Regional Greenhouse Gas Initiative, described in more detail below, participating states use emission budgets and a trading program to address CO$_2$ emissions from the electricity sector.
system plays the important function of allowing some EGUs to reduce their generation while ensuring that overall electricity demand can be reliably met. It is worth noting that adoption by affected EGUs of any of the measures in the building blocks could be (or could have been) used to facilitate compliance with each of the programs just described.

Some states are already relying on the integrated nature of the electricity system to establish the policy contexts within which affected EGUs will reduce their CO₂ emissions. California and Colorado provide two examples of how statewide targets (or company-wide targets within a state) can be designed with consideration of the wide range of CO₂ mitigation options and affected EGUs’ flexibility to use those options.

California enacted its Global Warming Solutions Act (also known as AB32) in 2006, requiring the state to reduce its GHG emissions to 1990 levels by 2020 and 80 percent below 1990...

levels by 2050. 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.”

California therefore relied on a suite of mechanisms to provide fossil fuel-fired generation substitutes and incentives for EGUs to reduce their emissions, including demand-side energy efficiency programs, renewable energy programs, and an economy-wide cap-and-trade program, along with other programs. The California plan has put in place mechanisms that through market dynamics affect both companies’ longer-term planning decisions and their short-term dispatch decisions. The need to hold emissions allowances and the reduced demand from demand-side energy efficiency programs impact longer-term decisions companies make.

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189 December 27, 2013 Letter from Mary D. Nichols, Chairman of California Air Resources Board, to EPA Administrator Gina McCarthy.
about investment in both existing and new EGUs. The price of emission allowances also impacts hourly dispatch decisions; where emission allowance requirements are in effect, EGU owners routinely recognize the costs of emission allowances as components of the variable operating costs that are relied on for these decisions. In this manner, allowance prices constitute market signals encouraging reduced use of higher-emitting EGUs and increased use of lower-emitting EGUs.

The Colorado Clean Air Clean Jobs Act (CACJA), signed into law on April 19, 2010, required each investor-owned utility with coal-fired EGUs to submit to the state a multi-pollutant plan for meeting current and foreseeable EPA standards for emissions of NOx, SO2, particulates, mercury, and CO2. Rather than fully prescribing specific control technologies, the law provided flexibility for each utility to select the best set of measures to achieve the emission reductions. For example, a utility could choose to retrofit or repower EGUs, or it could choose to retire higher-emitting EGUs and replace them with NGCC units and other low- or non-emitting energy plants or with end-use

191 The requirement to hold allowances covering their CO2 emissions went into effect for EGUs in California on January 1, 2013.

192 The law also set some explicit requirements, such as requirements for development of new renewable generating capacity and requirements to phase out older coal-fired EGUs.
efficiency measures. The Colorado plan generally focused more on impacting companies’ longer-term planning decisions than on affecting short-term dispatch decisions. In response, Colorado utilities have adopted a mix of measures including retrofits, natural gas conversions and retirements of coal-fired EGUs, as well as construction of new NGCC units.

Regional mechanisms with analogous impacts on both longer-term planning decisions and short-term dispatch decisions have also been put in place. For example, nine northeastern and Mid-Atlantic States participate in the Regional Greenhouse Gas Initiative (RGGI), a market-based emissions budget trading program that sets an aggregate limit on CO2 emissions from fossil fuel-fired EGUs in the participating states. To comply with the program, each EGU must acquire allowances equal to its emissions in each compliance period – through purchases or by allocation from the state – and must surrender the allowances at the end of the period. The RGGI program offers flexibility to regulated parties through provisions for multi-year compliance periods, allowance banking, offsets, an auction reserve price, and a

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194 Participating states include Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont.
cost-containment reserve of allowances, and further encourages emission allowance market development by authorizing trading between regulated and non-regulated parties. Operating in this regime, EGUs take a variety of compliance actions, including replacing generation at higher-emitting EGUs with generation at lower-emitting EGUs or achieving emissions reductions at EGUs by means of end-use energy efficiency programs.

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

developers of new EGUs including renewable generating capacity (building block 3), and developers of demand-side resources (building block 4) all compete to provide potential resources for meeting the projected demand for electricity services.

As indicated by the foregoing discussion, in the U.S. electricity system, the demand for electricity services is met, on both a short-term and longer-term basis and in both regulated and deregulated contexts, through integrated consideration of a wide variety of possible options, coordinated by some combination of utilities, regulators, system operators, and market mechanisms. The EPA believes that the BSER for CO₂ emissions from existing EGUs should reflect this integrated character.

Importantly, experience has shown that because the grid is interconnected, CO₂ emissions reductions can be achieved through several different mechanisms, which differ primarily in their timing and in the extent of their advance planning: (i) Establishing and implementing a plan in advance under which a specific amount of generation from higher-emitting fossil fuel-

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196 Potential heat rate improvements create opportunities for EGU owners to reduce their variable costs, which increase potential operating profits from generation and thereby create opportunities to lower the prices at which the owners would bid the capacity of their EGUs into the auctions.
fired EGUs is substituted for the same amount of generation from, or avoided from, specific measures in building blocks 2, 3, and 4. (ii) Instituting measures in building blocks 2, 3, and 4, which, because of the interconnected nature of the grid, result in drawing utilization away from higher-emitting fossil fuel-fired EGUs, even in the absence of a plan in advance that targets those EGUs. (iii) Reducing utilization from higher-emitting fossil fuel-fired EGUs, which because of the interconnected nature of the grid and its operation in the regulated markets, leads to the measures in building blocks 2, 3, and 4 that develop or utilize replacement generation or demand-side energy efficiency, even in the absence of a plan in advance that includes those measures. The existence of these mechanisms supports what we propose in this rulemaking as the two alternative “best system[s] of emission reduction ... adequately demonstrated,” as discussed below.

4. Evaluation of individual building blocks against the BSER criteria

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

a. Building block 1 – heat rate improvements

Building block 1 – reducing the carbon intensity of generation at individual affected coal-fired steam EGUs through heat rate improvements – is a component of the BSER because the measures the affected sources may undertake to achieve heat rate improvements are technically feasible and of reasonable cost, and meet the other requirements to qualify as a component of the BSER.

The EPA’s analysis and conclusions regarding the technical feasibility, costs, and magnitude of CO₂ emission reductions achievable through heat rate improvements are discussed in section VI.C.1 above. We consider heat rate improvement to be a common and well-established practice within the industry.

Other BSER criteria also favor building block 1 as a component of BSER. For example, with respect to non-air health and environmental impacts, heat rate improvements cause fuel to be used more efficiently, reducing the volumes of and therefore the adverse impacts associated with disposal of coal combustion waste products. With respect to technological innovation, building block 1 encourages the spread of more advanced
As noted above, the EPA is concerned about the potential “rebound effect” associated with building block 1 if applied in isolation. More specifically, we noted that in the context of the integrated electricity system, absent other incentives to reduce generation and CO₂ emissions from coal-fired EGUs, heat rate improvements and consequent variable cost reductions at those EGUs would cause them to become more competitive compared to other EGUs and increase their generation, leading to smaller overall reductions in CO₂ emissions (depending on the CO₂ emission rates of the displaced generating capacity). However, we believe that this concern can be readily addressed by ensuring that the BSER also reflects other CO₂ reduction strategies that discourage overall increases in coal-fired generation or fossil fuel-fired generation, thereby allowing building block 1 to be considered part of the BSER for CO₂ emissions at affected EGUs.

b. Building block 2 – re-dispatch
Building block 2 – reducing CO₂ emissions at, and substituting for, generation from the most carbon-intensive affected EGUs with generation from less carbon-intensive affected EGUs (including NGCC units under construction) – is a component of the BSER because the shifts in generation that it involves demonstrate that reducing mass CO₂ emissions at higher-emitting EGUs is technically feasible, will not jeopardize system reliability, is of reasonable cost, and meets the other requirements for a component of the BSER.

The EPA’s analysis and conclusions regarding the technical feasibility, costs, and magnitude of CO₂ emission reductions achievable at high-emitting EGUs through re-dispatch among affected EGUs are discussed in section VI.C.2 above. We consider re-dispatch among the large number of diverse EGUs that are linked to one another and to customers by extensive regional transmission grids to be a routine and well-established operating practice within the industry that is used to facilitate the achievement of a wide variety of objectives, including environmental objectives, while meeting the demand for electricity services. As discussed above, in the interconnected and integrated electricity industry, fossil fuel-fired steam EGUs are able to reduce their generation and NGCC units are able to increase their generation in a coordinated manner through
mechanisms – in some cases centralized and in others not – that regularly deal with such changes on both a short-term and a longer-term basis. There is a long-term industry trend away from coal-fired generation and toward NGCC generation. States can encourage this trend in a variety of ways. First, a state could use its permitting authority to impose limits on the hours of operation (or emissions) of individual steam generating units over a given time period. Second, a state could change the relative costs of generation for more carbon-intensive and less carbon-intensive generating units by imposing a cost on carbon emissions. A state could do so through any of several market-based mechanisms. One would be to adopt an allowance-based system. An example is the Regional Greenhouse Gas Initiative, an allowance-based system in which sources purchase allowances in periodic auctions. Another way would be through a tradable emission rate system, under which the state would impose an emission rate limit on the steam generating unit that the unit could meet only by purchasing the right to average its emission rate with a unit with a lower rate, such as an NGCC unit. Most broadly, an allowance system would provide the greatest incentive for the most carbon-intensive affected sources to reduce emissions as much as possible so as to reduce their need to purchase allowances (or to allow them to sell un-needed...
allowances), and the same would be true for a tradable emission rate system.

    The emission reductions achievable or supported by the application of building block 2 also perform well against other BSER criteria. For example, we expect that building block 2 would have positive non-air health and environmental impacts. Coal combustion for electricity generation produces large volumes of solid wastes that require disposal, with some potential for adverse environmental impacts; these wastes are not produced by natural gas combustion. The intake and discharge of water for cooling at many EGUs also carries some potential for adverse environmental impacts; NGCC units generally require less cooling water than steam EGUs.197 As already noted, with respect to energy impacts, the EPA believes that building block 2 (at least at the level of stringency proposed for purposes of establishing state goals) would not pose risks to reliability. Building block 2 also promotes greater use of the advanced NGCC technology installed in the existing fleet of NGCC units.

    It should be observed that, by the building block’s definition, the shifts in generation taking place under building block 2 occur entirely among existing EGUs subject to this

197 Some NGCC units use air rather than water for cooling purposes.
Through application of this building block considered in isolation, some affected sources - mostly coal-fired steam EGUs - would reduce their generation and CO₂ emissions, while other affected sources - NGCC units - would increase their generation and CO₂ emissions. However, because for each MWh of generation, NGCC units produce less CO₂ emissions than coal-fired steam EGUs, the total quantity of CO₂ emissions from all affected sources in aggregate would decrease. In the context of the integrated electricity system, where the operation of affected EGUs of multiple types is routinely coordinated to provide a fungible service, and in the context of CO₂ emissions, where location is a less important factor than is the case for other pollutants, the EPA believes that a measure that takes advantage of that integration to reduce CO₂ emissions from the overall set of affected EGUs is readily encompassed within the meaning of a “system of emission reduction” for CO₂ emissions at affected EGUs even if the measure would increase CO₂ emissions.

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

199 Because building blocks 3 and 4 reduce generation and CO₂ emissions from all fossil fuel-fired affected EGUs as a group, including NGCC units, the increase in generation and CO₂ emissions from NGCC units under building block 2 is mitigated to some extent by including those building blocks in the BSER along with building block 2.
emissions from a subset of those affected EGUs. Emission trading or averaging approaches can facilitate the implementation of such a “system” and have already been used in the electricity industry to address CO₂ as well as other pollutants, as discussed above.

Finally, the EPA notes that the alternative interpretation of the BSER discussed later is based in part on the re-dispatch measures in building block 2. In this alternative, reduced generation from fossil fuel-fired steam EGUs is a component of the BSER. The potential to use increased generation from less carbon-intensive NGCC units would serve as a basis for quantifying the amounts of generation reductions and CO₂ emission reductions at more carbon-intensive EGUs that could be achieved while continuing to meet the demand for electricity services in a reliable and affordable manner. This alternative is discussed further in section VI.E.6 below.

c. Building block 3 – use of expanded low- and zero-carbon generating capacity

Building block 3 – reducing CO₂ emissions at and substituting for generation from affected EGUs by using expanded amounts of low- and zero-carbon generating capacity – is a component of the BSER because the expansion and use of renewable generating capacity, completion and use of new nuclear capacity,
and avoidance of nuclear capacity retirements all establish the foundation for a determination that mass emission reductions from affected EGUs are technically feasible, do not jeopardize system reliability, are of reasonable cost, and meet the other requirements for a component of the BSER.

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

The renewable capacity measures in building block 3 generally perform well against other BSER criteria. For example, incentives for expansion of renewable capacity encourage technological innovation in improved renewable technologies as well as more extensive deployment of current advanced technologies. Generation from wind turbines (the most common renewable technology) does not produce solid waste or require cooling water, a better environmental outcome than if that amount of generation had instead been produced at a typical range of fossil fuel-fired EGUs. Although the intermittent nature of generation from renewable resources such as wind and solar units requires special consideration from grid operators, as discussed above renewable generation has grown quickly in recent years, and the EPA has seen no evidence that operators will be less able to cope with future growth than they have with rapid past growth. Further, if a state were concerned that increasing the use of NGCC capacity might create risks to reliability in the form of potential inadequacies in natural gas infrastructure, use of expanded renewable generation capacity could help address that concern.
The EPA believes that the performance of the nuclear measures in building block 3 against the other BSER measures is acceptable. With respect to encouragement of technological innovation, incentives for completion of new nuclear capacity encourage deployment of nuclear unit designs that reflect advances over earlier designs. The nation’s nuclear fleet today routinely operates at high average utilization rates, suggesting no reason to expect adverse reliability consequences from completion or preservation of additional nuclear capacity. Use of expanded nuclear capacity would be another way for a state to address any concern that increasing the use of NGCC capacity might create risks to reliability in the form of potential inadequacies in natural gas infrastructure. New nuclear units would have closed-cycle cooling systems with lower cooling water usage than some existing fossil fuel-fired EGUs; existing nuclear units may use amounts of cooling water comparable to the amounts used by those fossil fuel-fired steam EGUs. The EPA recognizes that nuclear generation poses unique waste disposal issues (although it avoids the solid waste issues specific to coal-fired generation). However, we do not consider that potential disadvantage of nuclear generation relative to fossil fuel-fired generation as outweighing nuclear generation’s other advantages as an element of building block 3. For all these
reasons, we consider building block 3 to be a component of the “best system of emission reduction ... adequately demonstrated.”

Finally, the EPA notes that under alternative BSER discussed later would include a component consisting of reduced generation from affected EGUs, with the measures in building block 3 serving as a basis for quantifying the amount of reduced generation and consequent CO₂ emission reductions. Because of the availability of those measures, the amount of reduced generation can be achieved while continuing to meet the demand for electricity services in a reliable and affordable manner. This alternative BSER is discussed in section VI.E.6 below.

d. Building block 4 – increased demand-side energy efficiency

Building block 4 – reducing CO₂ emissions at and reducing generation from affected EGUs by promoting demand-side energy efficiency that reduces the amount of generation required from affected EGUs – is a component of the BSER because the demand-side energy efficiency is technically feasible and of reasonable cost, and meets the other requirements for a component of the BSER.

The EPA’s analysis and conclusions regarding the technical feasibility, costs, and magnitude of the building block 4 are discussed in section VI.C.4 above. We consider demand-side
energy efficiency programs to be proven, well-established practices within the industry that are consistent with industry trends. States can and do authorize or require implementation of demand-side energy efficiency programs. Fossil fuel-fired EGUs can reduce their generation. Owners of affected EGUs as well as other parties can contract for demand-side energy efficiency. As discussed above, coordination of these decisions in the integrated electricity system can occur through a variety of mechanisms, some centralized and some not. For example, an allowance system or tradable emission rate system would provide incentives that promote the measures in building block 4 in the same manner as discussed above for other building blocks. Building block 4 is also very attractive under other BSER criteria. Demand-side energy efficiency avoids the non-air health and environmental effects of the fossil fuel-fired generation for which it substitutes. Further, by reducing the overall amount of electricity that needs to be transmitted between EGUs and customers, demand-side energy efficiency tends to relieve stress on the grid, thereby increasing system reliability. Creating incentives for additional demand-side energy efficiency is also consistent with the goals of encouraging technological innovation in energy efficiency and encouraging deployment of current advanced technologies. For all
these reasons, the measures in building block 4 qualify as a component of the “best system of emission reduction ... adequately demonstrated.”

The EPA notes that the alternative BSER discussed later would include a component consisting of reduced generation from affected EGUs, with demand-side energy efficiency serving as a basis for quantifying the amounts of generation reductions and consequent CO₂ emission reductions that can be achieved while continuing to meet the demand for electricity services in a reliable and affordable manner. This alternate interpretation of the BSER is discussed in section VI.E.6 below.

5. Evaluation of building block combinations against the BSER criteria

a. Combination of building blocks 1 and 2

The EPA has considered whether a combination of building blocks 1 and 2 would be the BSER. As described in section VI.D above, we believe that such a combination is technically feasible and would be a “system of emission reduction” capable of achieving meaningful reductions in CO₂ emissions from affected EGUs at a reasonable cost. The combination would also satisfy other BSER criteria. Nevertheless, we do not propose that this combination should be the BSER because the proposed combination...
of all four building blocks is capable of achieving greater
reductions in CO\textsubscript{2} emissions from affected EGUs at a lower cost.

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

With respect to most of the BSER criteria, there is no
reason to expect that the combination of building blocks 1 and 2
would be evaluated differently than the individual building
blocks. However, as noted earlier, the combination addresses the
concern about building block 1 regarding a potential rebound
effect, and in that important respect it performs better than
building block 1 considered in isolation. The substitution of
NGCC generation for generation from coal-fired and other steam
EGUs ensures that generation from coal-fired EGUs, as a group,
would not increase as a result of their improved variable costs,
with the result that the reduction in CO₂ emission rates of coal-fired EGUs brought about by heat rate improvements would on average be accompanied by a reduction in CO₂ emissions from those EGUs. The combination of building blocks would therefore be capable of achieving greater reductions in CO₂ emissions from affected sources than either building block in isolation.

By reducing overall generation from coal-fired EGUs, the combination of building blocks 1 and 2 also has the potential to raise the cost of emission reductions achievable through heat rate improvements relative to the cost if building block 1 were implemented in isolation.200 However, the EPA believes that the cost of emission reductions achieved through heat rate improvements would remain reasonable for two reasons. First, as discussed in section VI.C.1 above, the cost of CO₂ emission reductions achievable through heat rate improvements is quite low, and that cost would remain reasonable even if substantially increased. Second, although under the combination of building blocks 1 and 2 the volume of coal-fired generation would

200 If an EGU produces less generation output, then an improvement in that EGU’s heat rate and rate of CO₂ emissions per unit of generation produces a smaller reduction in CO₂ emissions. If the investment required to achieve the improvement in heat rate and emission rate is the same regardless of the EGU’s generation output, then the cost per unit of CO₂ emission reduction will be higher when the EGU’s generation output is lower.
decrease, that decrease is unlikely to be spread uniformly among all coal-fired EGUs. It is more likely that some coal-fired EGUs would decrease their generation slightly while others would decrease their generation by larger percentages or cease operations altogether. Some coal-fired EGUs could increase their generation. We would expect EGU owners to take these changes in EGU operating patterns into account when considering where to invest in heat rate improvements, with the result that there would be a tendency for such investments to be concentrated in EGUs whose generation output was expected to decrease the least (or to increase). This enlightened bias in spending on heat rate improvements would tend to mitigate any deterioration in the cost of CO₂ emission reductions achievable through heat rate improvements.

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

b. Combination of all four building blocks

The EPA’s proposed BSER is a combination of all four building blocks. For the reasons described below, and like each of the building blocks, the combination must be considered a “system of emission reduction.” Moreover, as also discussed below, the combination qualifies as the “best” system that is...
“adequately demonstrated.” The combination is technically feasible; it is capable of achieving meaningful reductions in CO₂ emissions from affected EGUs at a reasonable cost; it satisfies the other BSER criteria as well; and it is well-established. Further, because the combination of all four building blocks would achieve greater CO₂ emission reductions at a lower cost than the combination of building blocks 1 and 2 described above, and would also perform better against other BSER criteria, we propose to find the combination of all four building blocks to be the “best system of emission reduction ... adequately demonstrated” for reducing CO emissions at affected EGUs.  

Because the measures in building blocks 2, 3, and 4 involve the interconnected electricity grid, evaluating them against the criteria for the BSER involves certain considerations. The EPA discusses these in the Legal Memorandum, and summarizes them briefly below.

The EPA’s proposal that the “system of emission reduction” includes the measures in building blocks 2, 3, and 4 is grounded in the EPA’s interpretation of the key CAA provisions: section 201. The analysis of the interactions among building blocks provided above for the combination of building blocks 1 and 2 applies to the combination of all four building blocks as well. The EPA believes that in combination, each of the four building blocks would achieve substantial reductions in CO₂ emissions from affected EGUs at a reasonable cost.
111(d)(1), which requires that each state’s plan “establish[] standards of performance for any existing source” for certain types of air pollutants; and section 111(a)(1), which defines a “standard of performance” as “a standard for emissions ... which reflects the degree of emission limitation achievable through the application of the best system of emission reduction ... adequately demonstrated.” These provisions require that, in this rulemaking, the affected sources must be subject to emissions standards, but the basis for those standards – the “system of emission reduction” – may be any system that reduces the affected sources’ emissions. As discussed in the Legal Memorandum, the EPA is justified in adopting this interpretation under the first step of the framework for administrative agencies to construe statutes that the U.S. Supreme Court established in Chevron U.S.A. Inc. v NRDC, 467 U.S. 837, 842-844 (1984) (Chevron), which we refer to as Chevron step 1.

Specifically, the term “system,” which is not defined in the CAA, is broad: “a set of things working together as parts of a mechanism or interconnecting network.”202 The remaining provisions of the definition of “standard of performance” do not

include any constraints on the “set of things” that may constitute a “system of emission reduction.” Nor does the context in which “standard of performance” is found – the provisions of section 111(d)(1) – add constraints on the things that may constitute such a system. Rather, it is clear from these CAA provisions that anything that reduces the emissions of affected sources may be considered a “system of emission reduction” for those sources. For this reason, the measures in building blocks 2, 3, and 4 must be considered components of such a system.

Even if these CAA provisions leave room for interpretation as to whether those measures must be considered components of such a system, the EPA’s interpretation that they do is reasonable. As discussed in the Legal Memorandum, the EPA is justified in adopting this interpretation under the second step of the Chevron framework, which we refer to as Chevron step 2. There are several reasons. In enacting the CAA, Congress established “pollution prevention” as a “primary goal” of the Act, and described it as “the reduction or elimination, through any measures, of the amount of pollutants produced or created at the source.”

Building blocks 2, 3, and 4 are pollution prevention measures, and, in light of the importance of

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203 CAA §101(a)(3), (c).
pollution prevention in the CAA, it is reasonable to interpret “system of emission reduction” in section 111 to incorporate those measures. In addition, the breadth of “system of emission reduction” is confirmed by contrasting it with other provisions in the CAA that prescribe specific types of controls as the basis for emission limits.204 Further support is found in Title IV of the CAA, in which Congress established the program that regulates fossil fuel-fired power plants to reduce their emissions of \( \text{SO}_2 \) and \( \text{NO}_x \), the precursors to acid deposition. In designing Title IV, Congress recognized the integrated nature of the electricity sector and how that integration could be harnessed to reduce air pollutant emissions; and, in fact, Congress included provisions to encourage re-dispatch to lower-emitting sources, renewable energy, and demand-side energy efficiency, all of which are measures in those building blocks.205 All this supports the reasonableness of interpreting “system of emission reduction” in section 111 to incorporate

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

205 CAA §401(b), 404(f)-(g).
those measures. It should also be noted that a number of commentators in the private sector and academia have indicated support for interpreting the term, “system of emission reduction” to base the section 111(d) standards of performance on measures such as re-dispatch, renewable energy, and demand-side energy efficiency. Some stakeholders have as well. See Nordhaus R., Gutherz I., “Regulation of CO2 Emissions from Existing Power Plants Under §111(d) of the Clean Air Act: Program Design and Statutory Authority,” Environmental Law Reporter, 44: 10366, 10384 (May 2014) ("strong arguments for interpreting “system” to include measures such as the addition of new zero-carbon generating capacity and increases in end-user energy efficiency"); Sussman R., “Power Plant Regulation Under the Clean Air Act: A Breakthrough Moment for U.S. Climate Policy?” Virginia Environment Law Journal, 32:97, 119 (2014) ("EPA would seem to have discretion to define ‘system’ to include any mix of strategies effective in reducing emissions."); Konschnik K., Peskoe A., “Efficiency Rules: The Case for End-Use Energy Efficiency Programs in the Section 111(d) Rule for Existing Power Plants,” Harvard Law School Environmental Law Program – Policy Initiative 4 (March 3, 2014) (EPA is authorized to “consider[] … the entire [electricity grid] system when setting performance standards.”); Monast J., Profeta T., Pearson B., Doyle J., “Regulating Greenhouse Gas Emissions From Existing Sources: Section 111(d) and State Equivalency,” Environmental Law Reporter, 42: 10206, 10209 (March 2012) ("Demand-side energy-efficiency programs and renewable energy generation may fit within the §111 framework, however, because both reduce the utilization of power plants …). According to this reasoning, emission reductions are occurring within the source category, because of changes in generation at the power plant.").

As described earlier with respect to the individual building blocks, the measures in each of building blocks 2, 3, and 4 qualify as components of the “best system of emission reduction adequately demonstrated.” The evaluations above of the individual building blocks against the criteria for the BSER generally apply to the combination of all four building blocks as well.

In addition, the measures in building blocks 2, 3, and 4 are “adequately demonstrated” because, as discussed, due to the integrated nature of the electricity system, they have long been relied on to reduce costs in general, assure reliability, and implement pre-existing pollution control requirements in the least cost manner. As also noted elsewhere in the preamble, some utilities, states and regions are already relying on these measures for the specific purpose of reducing CO\textsubscript{2} emissions from EGUs.

Further, measures in building blocks 2, 3, and 4 may be undertaken by the affected EGUs themselves, which confirms that these measures are “adequately demonstrated.”

doniger.pdf; Doniger D., “Questions and Answers on the EPA’s Legal Authority to Set ‘System Based’ Carbon Pollution Standards for Existing Power Plants under Clean Air Act Section 111(d),” NRDC (Natural Resources Defense Council) Issue Brief (Oct. 2013).
Each state’s electric utility sector has unique circumstances, and the EPA’s proposal ensures that states retain flexibility to craft standards of performance that can accommodate characteristics including fuels sources, types of EGU owners within a state (e.g., investor-owned, municipal, and cooperative utilities, and independent power producers), and regulatory structure (e.g., regulated or restructured). States can tailor their regulatory mechanisms to recognize differences, for example by creating budgets on a company-wide basis or using market-based mechanisms such as mass-based trading systems, to ensure that requirements are achievable.

The proposal also recognizes that states have different resource bases and energy policies in place. For instance, while the EPA’s BSER assumptions consider re-dispatch to NGCC units, they do not consider re-dispatch beyond the NGCC capacity already existing in a state. In that way, the proposal does not presume that states with limited natural gas generation or infrastructure will have to develop those resources.

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

The EPA also believes that owners of units operating across a wide range of corporate, institutional and market structures (e.g., vertically integrated utilities in regulated markets, independent power producers, municipal utilities, and rural cooperatives) can take advantage of a broad range of reduction opportunities included in the building blocks. Because of the proposed compliance time-frame, owners can consider longer-term options such as implementing energy efficiency programs or replacement of older generating resources with more modern types of generation, as well as shorter-term options such as heat rate improvements and re-dispatch. Many companies, for example, already factor a carbon cost adder into their long-term planning decisions.

Large vertically integrated utilities generally have options within all four building blocks. They tend to have large and, as a general matter, at least somewhat diverse generation fleets. For their higher-emitting units, they have opportunities to use measures that reduce the units’ CO₂ emission rates, such
as heat rate improvements, co-firing, or fuel switching. While this proposal preserves fuel diversity, with over 30 percent of projected 2030 generation coming from coal and over 30 percent from natural gas, even companies that have traditionally depended upon coal to supply the majority of their generation are diversifying their fleets, increasing their opportunities for re-dispatch.\textsuperscript{208} Within the 5-to-15-year planning horizon established in this proposal to begin in June 2015, most of these companies are likely to be investing in new generation and can consider options such as increased reliance on new renewable generating capacity. They also run energy efficiency programs for their customers.

Municipal utilities and rural cooperatives that own their own generation also have multiple options for reducing CO\textsubscript{2} emissions, particularly generation and transmission cooperatives and larger municipal utilities. They can implement unit-specific improvements, re-dispatch to lower emitting resources, employ energy efficiency and renewable energy strategies, and explore longer-term capacity planning strategies. For cooperatives and municipal utilities with smaller fleets, re-dispatching among their own units may not provide as many opportunities, particularly in the short term. But because of the timing

\textsuperscript{208} http://online.wsj.com/article/PR-CO-20140508-915605.html.
flexibility in the guidelines, these owners can use both short-term dispatch strategies and longer-term capacity planning strategies to reduce GHG emissions. At the same time, in formulating their compliance plans, states will be in a position to recognize the distinctive attributes of smaller utilities—and, of course, may consider participating in integrated multi-state compliance strategies to increase the flexibility and cost-saving opportunities that would be available to the covered EGUs.

Municipal utilities and rural cooperatives can face other challenges as well. In deregulated areas, even though they may be fully vertically integrated entities, they may not have as much flexibility to control dispatch because they are operating in a competitive market, where they can be in a position where they need to operate if called upon. Even in this case, the timing flexibility of the rule allows them to consider longer-term capacity planning strategies. These can include building or contracting for electric supply from lower-emitting sources, use of distributed renewable technologies, and use of demand-side energy efficiency measures. There are a number of municipal
Utilities and rural cooperatives that are already aggressively pursuing such strategies.\textsuperscript{209}

Independent power producers (IPPs) may also face unique challenges but nevertheless have options. Most IPP generating units are natural gas-fired, but IPP owners with coal-fired EGUs can implement efficiency improvements as well as other unit-level compliance options such as co-firing or fuel switching. While these types of companies do not use the integrated resource planning process that many vertically integrated utilities use, they still do long-term business planning and therefore are in a position to consider different long-term strategies related to their generating assets. Many IPPs are actively developing renewable generating capacity and natural gas-fired generating capacity. In addition, many IPPs participate in markets that allow both generating resources and demand-side resources to compete, so even though they do not directly serve customers, they have opportunities to participate in demand-side energy efficiency programs.

In a regulated state, if a company’s compliance strategies included reducing generation at higher-emitting EGUs, it would

work through its state’s integrated planning process to ensure that adequate generation was available through a combination of all four building blocks. In a restructured state, even if affected companies responded to the guidelines by reducing generation without themselves replacing that generation, the electricity markets that have developed would react to ensure the availability of replacement generation. Other companies would see opportunities to build or ramp up existing lower-emitting generation, and in some markets that treat demand-side resources on par with supply side resources, energy service companies would likely see opportunities. In all types of market structures, large energy users might independently see additional energy efficiency opportunities or opportunities for self-generation using options such as combined heat and power, solar, or power purchase agreements. As discussed in earlier portions of this section and elsewhere in the preamble, each of the building blocks is already being widely implemented, is consistent with industry trends, and consists of well-accepted CO2 reduction methods in the eyes of various stakeholders, as was clear from views expressed in our outreach process.

Moreover, there are mechanisms through which states could require measures from any of the building blocks in state plans. In fact, the state plan formulation process through which
section 111(d) is implemented reinforces the determination that these measures are components of the BSER. For example, states would have authority to impose measures such as best practices for operation and maintenance of EGUs, dispatch limits, renewable energy resource requirements, and demand-side energy efficiency requirements. States also would have authority to establish requirements that change the relative costs of generation from more carbon-intensive and less carbon-intensive EGUs, for example by creating emission allowance systems that cause market participants and system operators to take account of CO₂ emission rates as an element of variable operating costs. Such an approach can encourage measures from all of the building blocks simultaneously. As noted elsewhere in the preamble, many states have already pursued one or more of these approaches.²¹⁰

As has also been discussed in earlier portions of the preamble, the costs and energy impacts of each of the four building blocks individually are not unreasonable when viewed either at the individual source level or through the lens of the electricity system as a whole, a conclusion that holds for the combination of the building blocks as well. Moreover, the flexibility available to states and regulated entities to rely

²¹⁰ See the discussions of California AB32 and RGGI above in this section and elsewhere in the preamble.
more extensively in their plans and strategies on whichever measures best suit their particular circumstances will further improve cost-effectiveness. The analysis the EPA performed to assess the costs, benefits, and other impacts of the proposed goals reflects this compliance flexibility, along with transmission and pipeline capabilities and constraints, fuel market and electricity dispatch dynamics, and seasonal electricity load requirements. As described below in section X, the results indicate that the proposed state goals (discussed in section VII) are readily achievable with no adverse impacts on electric system reliability, and that impacts on retail electricity prices are modest and fall within the range of price variability seen historically in response to changes in factors such as weather and fuel supply. Further, the costs tend to decline over time as states and regulated entities take advantage of the available flexibility and expand deployment of more cost-effective measures (notably demand-side energy efficiency). The EPA considers this analysis strong confirmation of the cost effectiveness of the measures in the four building blocks in combination as the best system of emission reduction.

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

We welcome comment on this issue. As discussed above, we propose that the provisions of section 111 do not by their terms preclude the BSER from including those types of measures. In addition, as noted above, under our proposed approach, affected sources may themselves implement the measures included in building blocks 2, 3, and 4, so that those measures are within their control with the result of their application being emissions reductions at affected EGUs. Moreover, under our alternative approach, the “system of emission reduction” includes reductions in utilization at the affected sources themselves. It should also be noted that, as discussed above,

216 Commenters have critiqued this “at-the-unit” and “beyond-the-unit” distinction as follows:
the re-dispatch measures in building block 2 are limited to affected sources. Thus, the proposed approach and alternative described above respond to these stakeholder concerns.

6. Alternate interpretation of the best system of emission reduction

There is an argument that the at-the-unit/beyond-the-unit distinction is not a meaningful one. Specifically, it could be argued that the distinction between at-the-unit and beyond-the-unit measures is largely artificial, because all of the emission reductions under consideration—whether from at-the-unit measures (e.g., fuel-switching or efficiency upgrades) or from beyond-the-unit measures—are, in fact, emission reductions at or from electric generating units on the interconnected electric grid. For example, neither the addition of renewable generation nor the reduction of end-user demand directly reduces atmospheric emission of CO2; rather these measures permit fossil EGUs to reduce their own output and emissions. It can be argued that all of the systems of emission reduction here contemplated—whether they involve end-use energy efficiency, displacing high-emission generation with lower emission generation, fuel-switching, heat-rate improvements, etc.—are effectively at-the-unit measures that ultimately reduce emissions solely from regulated EGUs. If energy-efficiency programs, added renewable energy, and redispach from higher emitting facilities to lower emitting facilities are viewed as at-the-unit systems of emission reduction, the at-the-unit/beyond-the-unit distinction arguably becomes irrelevant—at least from a legal perspective. Rather, the real issue may come down to whether §111(d) authorizes EPA to require EGUs to curtail their output of electricity as a means of complying with the rule.

As an alternative to the approach described above for determining the “best system of emission reduction ... adequately demonstrated,” the EPA believes the “system of emission reduction” may be identified as including, in addition to building blocks 1 and 2, the reduction of EGUs’ mass emissions achievable through reductions in generation of specified amounts from fossil fuel-fired EGUs. Under this approach, the measures in building blocks 3 and 4 would not be components of the BSER but instead would serve as bases for quantifying the reduction in emissions resulting from the reduction in generation at affected EGUs, and assuring that the reduced generation is “adequately demonstrated” because it could be achieved while continuing to meet the demand for electricity services in a reliable and affordable manner. Specifically, the amount of generation from the use of expanded low- and zero-carbon generating capacity that could be provided, and the amount of generation from fossil fuel-fired EUGs that could be avoided through the promotion of demand-side energy efficiency, would determine the amount of the fossil fuel-fired generation reduction component of the BSER.

In a variation of this alternate interpretation of the BSER, instead of including building block 2 in the BSER, only the portion of building block 2 consisting of reductions in
generation at higher-emitting affected fossil fuel-fired steam EGUs would be included in the BSER. The portion of building block 2 consisting of increased generation at lower-emitting affected NGCC units would not be included in the BSER, but instead would serve as a basis for quantifying the amount of reduction in generation at higher-emitting affected EGUs that could achieved while continuing to meet the demand for electricity services in a reliable and affordable manner. Under this variation, to ensure that demand for electricity services can be met reliably, we propose that the amount of reduced generation from affected fossil fuel-fired steam EGUs is the amount of incremental generation that can be provided from affected NGCC units, and similarly we propose to find the cost of reduced generation from affected fossil fuel-fired steam EGUs reasonable only to the extent that the cost of the incremental generation from affected NGCC units is reasonable.

Reduced generation is encompassed by the clear terms of the phrase “system of emission reduction” because, in accordance with the above-discussed definition of “system,” reduced generation is a “set of things” – which include reduced use of generating equipment and reduced fuel input – that the affected
source may take to reduce its CO₂ emissions. If that phrase is not considered clear by its terms, then it may reasonably be interpreted to include reduced generation. As discussed in the Legal Memorandum, the legislative history of the CAA indicates that Congress recognized that emitting sources could comply with pollution control requirements by reducing production, including retiring. As also noted in the Legal Memorandum, examples of reduced utilization as a means of reducing emissions are found in settlement agreements between the EPA and fossil fuel-fired EGUs to resolve alleged violations of the CAA new source review (NSR) requirements.

Reduction of, or limitation on, the amount of generation is already a well-established means of reducing emissions of pollutants in the electric sector and not merely a theoretical option that is unavailable as a practical matter for sources that may have to operate to ensure system reliability. For example, reduced generation by higher-emitting sources is one of the compliance options available to, and used by, EGUs to comply

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217 For this reason, under a Chevron step 1 interpretation, “system of emission reduction” includes reduced generation.
218 For these reasons, under a Chevron step 2 interpretation, “system of emission reduction” includes reduced generation.
with the Clean Air Act acid rain program in CAA title IV, as well as the transport rules that we refer to as the NOx SIP Call\textsuperscript{220} and the Clean Air Interstate Rule (CAIR).\textsuperscript{221} Reduction in generation is also a possible means by which an EGU can achieve compliance with its requirements under RGGI. Reduced generation in specified amounts is the “best” system of emission reduction that is “adequately demonstrated” because it is technically feasible due to the source’s ability to limit its own operations. In addition, the amounts of generation and emission reductions may be determined with precision through the application of building block 2, 3, and 4 measures for increased generation from low- or zero-emitting sources and increased demand-side energy efficiency, which, in turn, ensure the reliability of the electricity grid and the affordability of electricity to business and consumers. Likewise, we propose to find the cost of reduced generation from affected EGUs reasonable only to the extent that the costs of the measures meeting the demand for energy services in the absence of that reduced generation are reasonable.

The levels of reduced generation proposed meet the criteria for the “best system of emission reduction ... adequately

\textsuperscript{220} 63 FR 57356 (Oct. 27, 1998).
\textsuperscript{221} 70 FR 25162 (May 12, 2005).
demonstrated.” The costs of the proposed levels of reduced generation are reasonable for the affected source category and the nation-wide electricity system, do not jeopardize reliability, and do promote the development and implementation of technology that is important for continued emissions reductions. This is because the extent to which the electrical grid operates through integrated generation, transmission and distribution networks creates fungibility for electricity and electricity services, which allows decreases in generation at one affected EGU to be seamlessly replaced by increased generation at a low- or zero-carbon EGU (building block 3) or by decreased demand (building block 4), or, in the variation described above, allows decreases in generation at affected fossil fuel-fired steam EGUs to be replaced by increases in generation at affected NGCC units (building block 2). These characteristics of the integrated electric system thereby make reduced generation a viable approach for achieving CO₂ emission reductions by affected EGUs.

As noted above, the measures in building blocks 2, 3, and 4 are already in widespread use in the industry. At the levels proposed, they have the technical capability to substitute for reduced generation at some or all affected EGUs at reasonable cost. The NGCC capacity necessary to accomplish the levels of
generation reduction proposed for building block 2 is already in operation or under construction. Moreover, it is reasonable to expect that the incremental resources reflected in building blocks 3 and 4 will develop at the levels requisite to ensure an adequate and reliable supply of electricity at the same time that higher-emitting EGUs may choose or be required to reduce their CO₂ emissions by means of reducing their utilization. There are two reasons for this. First, the affected sources themselves could invest in new renewable energy resources and demand-side energy efficiency, as discussed above. Second, the states, as part of their plans, have mechanisms available to put these substitutes in place: they could establish requirements or incentives that would result in new renewable energy and demand-side energy efficiency programs, as also discussed above.

7. EPA’s discretion in applying the criteria for the best system of emission reduction

\[222\] It should be noted that in light of the low current and projected near term prices for natural gas, market forces may lead investors to choose to build new NGCC units, rather than new renewable resources. This result would not call into question the technical feasibility of a BSER that included reductions in fossil fuel-fired generation by the amount of a specified amount of new renewable resources. This is because under these circumstances, the fossil fuel-fired generators could still reduce their generation without causing reliability or other problems in the electric power system.

\[223\] The nuclear generating capacity reflected in building block 3 is already in operation or under construction.
As discussed above, each of the approaches to determining the “best system of emission reduction ... adequately demonstrated” entails applying the criteria described in the D.C. Circuit case law for evaluating BSER. It should be emphasized that under the case law, the EPA has significant discretion in weighing the different criteria, and may weigh them differently in different rulemakings.

In the present rulemaking, the EPA is heavily weighting two criteria in particular: the amount of emissions reduction and the promotion of technology implementation – while also noting that the proposed BSER determination readily meets the other criteria as well. The EPA considers it especially important in this rulemaking, while ensuring that costs are not unreasonable, to achieve a significant amount of emissions reductions in response to the urgency and the magnitude of the need to mitigate climate change. Above, the EPA discusses this in the sections concerning the scientific background for this rulemaking. The EPA also considers it especially important in this rulemaking to promote technological innovation and development of, in particular, the measures in building blocks 3 and 4 (to reiterate, low- or zero-carbon electricity generation and demand-side energy efficiency, respectively). Promoting innovation in, and market penetration of, these technologies and
practices is critical to making the substantial reductions in emissions that will be required during the next few decades to reduce the risks of dangerous climate change.

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

8. 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 (i) 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 (ii) facilitating averaging or trading systems that include sources in both categories, which states may wish to adopt.

9. Severability

We consider our proposed findings of the BSER with respect to the various building blocks to be severable, such that in the event a court were to invalidate our finding with respect to any particular building block, we would find that the BSER consists of the remaining building blocks. The state goals that would result from any combination of the building blocks can be computed from data included in the Goal Computation TSD and its appendices using the methodology described in the preamble and that TSD.

10. 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 Memorandum in the docket, although, as noted, we are not soliciting comment on issues that were resolved by the implementing regulations and therefore are not being re-opened here. In particular, we invite comment on our analysis of the four building blocks as components of the BSER,
whether any other potential measures should be considered, and the legal, technical, and economic bases of our conclusions.

With regard to comments received during the stakeholder meetings, some commenters noted that trading programs like RGGI have been successful at reducing GHGs, and other commenters provided specific BSER proposals based on trading and/or emissions averaging approaches. We specifically request comment on whether any of these approaches should be considered as the BSER. We also specifically invite comment on the question, raised by some stakeholders, as to whether if measures may be relied on in the state plan to achieve emissions reductions, they cannot be excluded from the scope of the BSER solely because they involve actions by entities or at locations other than affected sources.

VII. State Goals

A. Overview

In this section, the EPA sets out proposed state-specific 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. As promulgated in the final rule following consideration of comments received, the interim and final goals will be binding emission guidelines for state plans.

The proposed goals are expressed in the form of state-specific, adjusted\textsuperscript{225} output-weighted-average CO\textsubscript{2} emission rates for affected EGUs. However, states are authorized to translate the form of the goal to a mass-based form, as long as the translated goal achieves the same degree of emission limitation.

The EPA is proposing that measures that a state takes after the date of this proposal and prior to the beginning of the plan period in 2020, and which result in CO\textsubscript{2} emission reductions during the plan period, would apply toward achievement of the

\textsuperscript{225} As described below, the emission rate goals include adjustments to incorporate the potential effects of emission reduction measures that address power sector CO\textsubscript{2} emissions primarily by reducing the amount of electricity produced at a state’s affected EGUs (associated with, for example, increasing the amount of new low- or zero-carbon generating capacity or increasing demand-side energy efficiency) rather than by reducing their CO\textsubscript{2} emission rates per unit of energy output produced.
state’s CO₂ goal. Thus, states with existing programs and policies, and states that put in place new programs and policies early, will be better positioned to achieve the goals.

At this time, the EPA is not proposing CO₂ emission performance goals for either Indian country or U.S. territories. The EPA does plan to establish CO₂ emission goals for both Indian country and territories. Emission goals for Indian country will be established in the future as necessary or appropriate, as provided for in the Tribal Authority Rule.

With respect to Indian country, the EPA is soliciting comment on the application of the four BSER building blocks to determine CO₂ emission performance goals for Indian country with affected EGUs. The EPA notes that some present and future actions taken to reduce criteria pollutants from EGUs in Indian country will result in significant CO₂ emission reductions. As the EPA has done in setting state goals, the EPA would set emission performance goals for Indian country in a manner that would allow the jurisdictional authority to meet the goals through the use of a wide range of policies and practices.

For example, a plan currently being implemented at the Four Corners plant to satisfy regional haze requirements calls for reduction of NOx emissions to be achieved in part by shutting down a portion of the plant’s generating capacity, and a similar plan has been proposed for the Navajo plant. See 78 FR 62509 (October 22, 2013).
capable of achieving CO₂ emission reductions. If the EPA develops one or more federal plans for EGUs located in Indian country, we are currently considering doing so on a regional basis in coordination with plans being developed for neighboring states. The EPA solicits comment on such an approach for a federal plan.

With respect to territories, the EPA requests comment on the appropriateness of the four building block approach for territories. In particular, the EPA solicits 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 data used to develop the renewable component of BSER for states.

The remainder of this section addresses five sets of topics. First, we discuss several issues related to the form of the goals. Second, we describe the proposed state goals and the computation procedure. Third, we discuss several types of state flexibility with respect to the goals. Fourth, we describe the alternate set of goals offered for comment and certain other approaches we considered. Finally, we discuss the proposal’s compatibility with the need to ensure a reliable, affordable supply of electricity.

Some of the topics addressed in this section are addressed in greater detail in supplemental documents available in the
docket for this rulemaking, including the Goal Computation TSD and the Greenhouse Gas Abatement Measures TSD. Specific topics addressed in the various TSDs are noted throughout the discussion below.

B. Form of goals

The proposed goals are presented in the form of adjusted output-weighted-average CO$_2$ emission rates that the affected fossil fuel-fired EGUs located in each state could achieve, on average, through 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 CO$_2$ per MWh of electricity generated), with the opportunity for the state to adopt a mass-based form (e.g., a cap on the tonnage of CO$_2$ emissions); the use of output-weighted-average emission rates for all affected EGUs in a state rather than nationally uniform emission rates for all affected EGUs of particular types; the use of adjustments to accommodate measures that reduce CO$_2$ emissions by reducing the quantity of fossil fuel-fired generation rather than by reducing the CO$_2$ emission rate per MWh generated by affected sources; the use of emission rates expressed in terms of net rather than gross energy output; and
the adjustability of the goals based on the severability of the underlying building blocks.

First, the EPA proposes to use an emission rate-based form for the state-specific goals included in the guidelines, and to give each state the opportunity to translate its rate-based goal to an equivalent mass-based form for state plan purposes. Each of the two forms of goals presents advantages. Defining emission performance levels in a rate-based form provides flexibility to accommodate changes in the overall quantities of electricity generated in response to increases in electricity demand. Defining emission performance levels in a mass-based form provides relative certainty as to the absolute emission levels that would be achieved as well as relative simplicity in accommodating and accounting for the emission impacts of a wide variety of emission reduction strategies. In light of these respective advantages, we propose to set an emission rate-based form of goal, and to allow any state to translate the rate-based goal to an equivalent mass-based emission performance level for state plan purposes. This approach allows each state to maximize the advantages it considers optimal and is consistent with the state flexibility principle that is central to the EPA’s development of this program.
The second aspect noted above concerns the proposed choice of state-specific output-weighted-average emission rates for all affected EGUs in each state rather than nationally uniform emission rates for particular types of affected EGUs. Here, the EPA’s main consideration has been to ensure that the proposed goals reflect opportunities to manage CO₂ emissions by shifting generation among different types of EGUs. 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 offers opportunities to achieve large amounts of CO₂ emission reductions at reasonable costs. These opportunities can be reflected in a goal established in the form of an output-weighted-average emission rate for multiple affected EGU types. Our approach is also consistent with the fact that the
proportions of different EGU types and hence the magnitudes of
the generation-shifting opportunities vary across states, and
that CAA section 111(d) calls for standards of performance to be
established in state plans rather than on a nationwide basis.

The third aspect noted above regarding the proposed form of
the goals concerns the adjustments made to the output-weighted-
average emission rates in order to accommodate reduced
utilization associated with measures such as increases in low-
and zero-carbon generating capacity and demand-side energy
efficiency. We recognize that these measures reduce overall CO₂
mass emissions from affected EGUs by reducing the quantity of
generation from affected EGUs without necessarily reducing the
weighted-average CO₂ emission rates of affected EGUs.

Accordingly, we have constructed the emission rate goals in a
manner that is intended to account for these generation
quantity-reducing measures by making adjustments to the values
used in the emission rate computations. The specific adjustments
are summarized below in the context of the goal computation
methodology and are described in greater detail in the Goal
Computation TSD. As described below in section VIII on state
plans, we are proposing that a state choosing a rate-based form
of goal would be able to make analogous adjustments when
assessing monitored emission performance so that measures that
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{227} rather than on CO₂ emission rates, because the emission-reducing effects of reduced generation at 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 \textit{of} generation measured at the point of delivery to the transmission grid rather than gross MWh \textit{of} generation measured at the EGU’s generator.\textsuperscript{228} (As discussed below in section VIII on state plans, we are similarly proposing that states choosing a rate-based form of emission performance level for their plans should establish a requirement for affected EGUs to report hourly net energy output.) The difference between net and gross generation is the electricity

\textsuperscript{227} 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{228} For some EGUs, total net or gross energy output also includes useful thermal output, in addition to either net or gross electric energy output.
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 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{229} to us under 40 CFR Part 75, and that the proposed GHG standards of performance for new EGUs are expressed in terms of gross generation (although we sought comment on the use of net generation instead). We therefore specifically seek comment on whether the goals and reporting requirements for existing EGUs should be expressed in terms of gross generation instead of net generation for consistency with existing reporting requirements and with the proposed requirements under the GHG standards of performance for new EGUs.

The final aspect noted above has to do with the severability of the four building blocks, discussed in section

\textsuperscript{229} Some EGUs report gross steam output instead of gross electrical load.
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. As noted above, the state goals that would result from any combination of the building blocks can be computed from data included in the Goal Computation TSD and its appendices using the methodology described below and in that TSD.

We invite comment on all aspects of the proposed form of the goals, 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 mass emission reductions by avoiding fossil fuel-fired 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 proposed goals are set forth in Table 6 below, followed by a description of the computation methodology. (The issue of how states could demonstrate emission performance consistent with the interim and final goals is addressed in Section VIII on state plans.)

### Table 6: Proposed 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>1,147</td>
<td>1,059</td>
</tr>
<tr>
<td>Alaska</td>
<td>1,097</td>
<td>1,003</td>
</tr>
<tr>
<td>Arizona</td>
<td>735</td>
<td>702</td>
</tr>
<tr>
<td>Arkansas</td>
<td>968</td>
<td>910</td>
</tr>
<tr>
<td>California</td>
<td>556</td>
<td>537</td>
</tr>
<tr>
<td>Colorado</td>
<td>1,159</td>
<td>1,108</td>
</tr>
<tr>
<td>Connecticut</td>
<td>597</td>
<td>540</td>
</tr>
<tr>
<td>Delaware</td>
<td>913</td>
<td>841</td>
</tr>
</tbody>
</table>

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 Indian country or U.S. territories at this time.
<table>
<thead>
<tr>
<th>State</th>
<th>2023</th>
<th>2022</th>
</tr>
</thead>
<tbody>
<tr>
<td>Florida</td>
<td>794</td>
<td>740</td>
</tr>
<tr>
<td>Georgia</td>
<td>891</td>
<td>834</td>
</tr>
<tr>
<td>Hawaii</td>
<td>1,378</td>
<td>1,206</td>
</tr>
<tr>
<td>Idaho</td>
<td>244</td>
<td>228</td>
</tr>
<tr>
<td>Illinois</td>
<td>1,366</td>
<td>1,271</td>
</tr>
<tr>
<td>Indiana</td>
<td>1,607</td>
<td>1,531</td>
</tr>
<tr>
<td>Iowa</td>
<td>1,341</td>
<td>1,301</td>
</tr>
<tr>
<td>Kansas</td>
<td>1,578</td>
<td>1,499</td>
</tr>
<tr>
<td>Kentucky</td>
<td>1,844</td>
<td>1,763</td>
</tr>
<tr>
<td>Louisiana</td>
<td>948</td>
<td>883</td>
</tr>
<tr>
<td>Maine</td>
<td>393</td>
<td>378</td>
</tr>
<tr>
<td>Maryland</td>
<td>1,347</td>
<td>1,187</td>
</tr>
<tr>
<td>Massachusetts</td>
<td>655</td>
<td>576</td>
</tr>
<tr>
<td>Michigan</td>
<td>1,227</td>
<td>1,161</td>
</tr>
<tr>
<td>Minnesota</td>
<td>911</td>
<td>873</td>
</tr>
<tr>
<td>Mississippi</td>
<td>732</td>
<td>692</td>
</tr>
<tr>
<td>Missouri</td>
<td>1,621</td>
<td>1,544</td>
</tr>
<tr>
<td>Montana</td>
<td>1,682</td>
<td>1,771</td>
</tr>
<tr>
<td>Nebraska</td>
<td>1,596</td>
<td>1,479</td>
</tr>
<tr>
<td>Nevada</td>
<td>697</td>
<td>647</td>
</tr>
<tr>
<td>New Hampshire</td>
<td>546</td>
<td>486</td>
</tr>
<tr>
<td>New Jersey</td>
<td>647</td>
<td>531</td>
</tr>
</tbody>
</table>
The proposed goals are expressed as adjusted output-weighted-average emission rates for all affected EGUs in a state. As discussed earlier in this section, a goal expressed as
an unadjusted output-weighted-average emission rate would fail to account for mass emission reductions from reductions in the total quantity of fossil fuel-fired generation associated with state plan measures that increase low- or zero carbon generating capacity or demand-side energy efficiency. Accordingly, under the proposed goals, the emission rate computation includes an adjustment designed to reflect those mass emission reductions. The adjustment is made by estimating the annual net generation associated with an achievable amount of qualifying new low-carbon and zero-carbon generating capacity, as well as the annual avoided generation associated with an achievable portfolio of demand-side energy efficiency measures, and adding those MWh amounts to the energy output from affected units that would have been used in an unadjusted output-weighted-average emission rate computation. 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

231 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.
adjustments to compliance measurement approaches under its state plan, thereby enabling the state to adopt an emission rate-based form of emission performance level while still being able to rely on low- or zero-carbon capacity deployment programs and demand-side energy efficiency as components of its plan.)

The methodology used to compute each state’s proposed goal is summarized on a step-by-step basis below. The methodology is described in more detail in the Goal Computation TSD, which includes a numerical example illustrating the full procedure. The development of the data inputs used in the computation procedure is discussed in section VI above and in the Greenhouse Gas Abatement Measures TSD.

Step 1 (compilation of baseline data). On a state-by-state basis, we obtained total annual quantities of CO₂ emissions, net generation (MWh), and capacity (MW) from reported 2012 data for all affected EGUs. For each state, we aggregated the 2012 data for all coal-fired steam EGUs as one group, all oil- and gas-fired steam EGUs as a second group, and all NGCC units as a third group. We aggregated the 2012 data for all remaining affected EGUs, i.e., integrated gasification combined-cycle

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.B. above.
(IGCC) units and any simple-cycle combustion turbines satisfying the size and electricity sales thresholds for qualification as affected EGUs) as a fourth, “other” group.\footnote{The emission and generation totals for the “other” group also reflect the portion of affected cogeneration units’ total CO\textsubscript{2} emissions and total energy output corresponding to those units’ useful thermal output.} 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.\footnote{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).} Capacity and emission rate data inputs for the post-2012 affected EGUs were obtained from the NEEDS database maintained by the EPA for use with the Integrated Planning Model (IPM). Generation data inputs for the post-2012 affected EGUs were estimated based on the average 2012 utilization rates for recently constructed EGUs of the same types; for example, we estimated in this step that the post-2012 NGCC units would operate at a 55 percent utilization rate on average.

Step 2 (application of building block 1). The total CO\textsubscript{2} emissions amount for the coal-fired steam EGU group in each state from Step 1 was reduced by six percent, reflecting our assessment of the average opportunity to reduce CO\textsubscript{2} emission...
rates across the existing fleet of coal-fired steam EGUs through heat rate improvements that is technically achievable at a reasonable cost.

Step 3 (application of building block 2). If the generation data for the NGCC group in a state developed in Step 1 showed average annual utilization below 70 percent of those units’ maximum possible output, and the generation data developed in Step 1 also included generation from the coal-fired steam or oil/gas-fired steam EGU groups in that state, the generation and emissions figures for the NGCC group were increased, and the generation and emissions figures for the coal-fired and oil/gas-fired steam EGU groups from Step 2 were proportionately decreased, to reflect an estimated potential increase in utilization of the NGCC group to a maximum of 70 percent. In this step, the total (across all four groups) of the state’s fossil fuel-fired generation was maintained at the amount computed in Step 1, but to the extent that in the analysis a portion of the total fossil generation was shifted from the coal-fired and oil/gas-fired steam EGU groups, which have higher

\[235\] 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.
CO₂ emission rates, to the NGCC group, which has a lower CO₂ emission rate, the total (across all four groups) of the state’s CO₂ emissions was reduced.\(^{236}\)

Step 4 (application of building block 3). We estimated the total quantities of renewable generating capacity and new or preserved nuclear capacity for each state under the “best practices” approaches discussed in section VI.C.3 above. Separate estimates of renewable generation were computed for each year of the plan period for each state based on the state’s 2012 renewable generation and a regional growth factor. Nuclear generation was estimated as the amount of new and preserved nuclear capacity for each state operated at a utilization rate of 90 percent, consistent with recent industry-wide average utilization rates for nuclear units.

Step 5 (application of building block 4). We estimated the total MWh amount by which generation from each state’s affected EGUs would be cumulatively reduced in each year of the plan period 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

\(^{236}\) We did not estimate any change in utilization, generation, or emissions for the state’s “other” group of IGCC units and simple-cycle combustion turbines in Step 3.
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 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 generation from renewable and nuclear generating capacity from Step 4 above plus (c) the estimated cumulative annual MWh amount saved through demand-side energy efficiency from Step 5 above.²³⁷

²³⁷ Expressed as a formula, the equation for the annual rate computation is:

\[
\frac{(\text{Coal gen.} \times \text{Coal emission rate}) + (\text{OG gen.} \times \text{OG emission rate}) + (\text{NGCC gen.} \times \text{NGCC emission rate}) + \text{“Other” emissions}}{\text{Coal gen.} + \text{OG gen.} + \text{NGCC gen.} + \text{“Other” gen.} + \text{Nuclear gen.} + \text{RE gen.} + \text{EE gen.}}
\]
We performed these computations separately for each year from 2020 to 2029, using the respective cumulative annual MWh savings figures developed in Steps 4 and 5.

Step 7 (computation of interim and final goals). The final 2030 goal for each state is the annual rate computed for 2029 for the state from Step 6 above. We computed the 2020-2029 interim goal for each state as the simple average of the annual rates computed for each of the years from 2020 to 2029 for the state from Step 6 above.

It bears emphasis that the procedure described above is proposed to be used only to determine state goals, and the particular data inputs used in the procedure are not intended to represent specific requirements that would apply to any individual EGU or to the collection of EGUs in any state. The specific requirements applicable to individual EGUs, to the EGUs in a given state collectively, or to other affected entities in the state would be based on the standards of performance established through that state’s plan. The details of how states could attain emission performance levels consistent with the goals through different state plan approaches that recognize emission reductions achieved through all the building blocks are discussed further in section VIII on state plans.
We invite comment on all aspects of the goal computation procedure. (Note that we also invite comment on certain specific alternate data inputs to the procedure in Section VI.C. above.) We also specifically invite comment on the state-specific historical generation and capacity data to which the building blocks are applied in order to compute the state goals, as well as the state-specific data used to develop the state-specific data inputs for building blocks 3 and 4. These data are contained in the Goal Computation TSD and the Greenhouse Gas Abatement Measures TSD.

With respect to building block 2, we specifically request comment on the following alternate procedure: in Step 3, to the extent that generation from a state’s NGCC group was increased consistent with the NGCC utilization rate target, in order to maximize the resulting emission reductions, we would decrease generation from the state’s coal-fired steam group first, and then decrease generation from the state’s oil/gas-fired steam group (instead of decreasing generation from the coal-fired steam and oil/gas-fired steam groups proportionately).

With respect to building block 4, we specifically invite comment on the alternative in Step 5 of scaling up the estimated reduction in the generation by affected EGUs in net electricity-exporting states to reflect an expectation that a portion of the
generation avoided by the demand-side energy efficiency efforts of other, net electricity-importing states would occur at those EGUs, analogous to the proposed adjustment for net importing states described in Step 5. We also request comment on the alternative of making no adjustment in Step 5 for either net electricity-importing or net electricity-exporting states. These alternatives are discussed in the Goal Computation TSD.

We also request comment on whether CO2 emission reductions from other measures not currently included in any of the four proposed building blocks should be included in the state goals.

D. State flexibilities

As promulgated in the final rule following consideration of comment, the state-specific goals will be binding emission guidelines. States' ability to achieve emission performance levels consistent with the binding goals is enhanced by several distinct types of flexibility: (i) choices as to the measures employed, including the timing of their implementation; (ii) the ability to translate from a rate-based form of goal to a mass-based form of goal; and (iii) the opportunity to pursue multi-state 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. In developing the building block data inputs applied to each state’s historical capacity and generation data to develop the goals, the EPA targeted reasonably achievable rather than maximum performance levels. The overall goals therefore represent reasonably achievable emission performance levels that provide states with flexibility to pursue some building blocks more extensively and others less extensively than the degree reflected in EPA’s data inputs while meeting the overall goals. States can also choose to include in their plans measures that are not included in the building blocks.

Further, by allowing states to demonstrate compliance over a multi-year interim plan period of as long as ten years, the EPA’s proposed approach increases states’ flexibility to choose among alternative potential measures. For example, by taking advantage of the multi-year flexibility, a state could choose to rely more heavily in its plan on measures whose effectiveness tends to grow over time, such as demand-side energy efficiency programs. This flexibility could also help states address concerns about stranded assets, for example, by enabling states...
to defer imposition of requirements on EGUs that may be scheduled to retire after 2020 but before 2029.

The second type of flexibility noted above is that while the EPA is proposing to establish goals in an emission rate-based form, we are also proposing to provide states with the flexibility to translate the rate-based goals to mass-based goals in order to accommodate states’ potential interest in having emission performance requirements measured in absolute tons. For example, the northeastern 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 emission 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 EPA’s approach allows states to submit multi-state plans. The EPA expects this flexibility to reduce the cost of achieving the state goals and therefore expects it to be
attractive to states. For example, the RGGI-participating states
could choose to submit a multi-state mass-based plan that
demonstrates emission performance 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 be allowed to quantify the level of emission reduction
resulting from the application of BSER or, if the EPA
establishes goals, the states should be allowed to adjust the
goals or to treat the goals established by the EPA as advisory
rather than binding. Consistent with the existing implementing
regulations for CAA section 111(d) at 40 CFR part 60, this
quantification is the EPA’s role.238 As discussed in the Legal
Memorandum, CAA section 111(d) directs the EPA to “prescribe
regulations which shall establish a procedure similar to that
provided by [CAA section 110] under which each State shall
submit” a section 111(d) state plan. As noted in preamble
section II.D above, the EPA promulgated implementing regulations

238 40 CFR 60.22(b)(5). We do not propose to re-open that portion
of the implementing regulations in this rulemaking.
in 1975, and has revised parts of them since. The regulations set out a multi-step process for the development and approval of state plans, and assign responsibility for the various steps in the process to the EPA or the states. The regulations provide that the EPA is to promulgate an “emission guideline that reflects the application of the best system of emission reduction (considering the cost of such reduction) that has been adequately demonstrated for” affected sources.239 In this manner, the regulations make clear that the EPA determines the BSER. In this rulemaking, as discussed above, the EPA identifies the BSER. In addition, in this rulemaking, the EPA applies the BSER to each state, and then, for each state, calculates the average emission rate that, in the words of the regulations just quoted, “reflects the application of the [BSER].” That average emission rate is the state goal.

By the same token, because the state goals are an integral part of the emission guidelines that the framework regulations authorize EPA to establish, the goals are binding, and the states, in their CAA section 111(d) plans, must meet those goals and may not make them less stringent. This matter, too, is

239 Id.
resolved by the implementing regulations. To reiterate, the proposed state goals represent the level of performance that is achievable through application of the BSER to the pertinent data for each individual state. States have the opportunity to comment on the proposed BSER, the proposed methodology for computing state goals based on application of the BSER, and the state-specific data that is proposed for use in the computations. We expect that the states will have an adequate opportunity to comment on the state goals during the comment period. Once the final goals have been promulgated, the states will be able to meet them because they will represent the application of BSER to the states’ affected sources. In addition, states have several types of flexibilities in developing their state plans: they have flexibility regarding the selection of the measures upon which they choose to rely and a 10-year time period over which to reach full implementation, and they can use rate-based or mass-based approaches. In addition, as we have noted, multi-state coordination offers states an opportunity to achieve additional emission reductions and reduce implementation costs. These flexibilities, discussed further in Section VIII of this preamble, ensure that states

241 Id. We do not propose to re-open that portion of the implementing regulations in this rulemaking.
will be able to achieve their final CO₂ emission performance goals and that no special provision for state adjustment of goals outside the normal notice-and-comment rulemaking process is warranted.²⁴²

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

²⁴² In the event that a state becomes concerned about its ability to meet the goal that the EPA promulgates for it, the state may submit to the EPA a petition for reconsideration, if that petition is based on relevant information not available during the comment period. See CAA §307(d)(7)(B).
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 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 7 below.

Table 7: 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>
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<tr>
<td>Alabama</td>
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<tr>
<td>Alaska</td>
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<td>1,431</td>
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<tr>
<td>Arizona *</td>
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<td>763</td>
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<tr>
<td>Arkansas</td>
<td>1,083</td>
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* See footnote accompanying Table 6 above.
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<tr>
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<th>Release</th>
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<td>627</td>
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<tr>
<td>Delaware</td>
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<td>983</td>
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<tr>
<td>Florida</td>
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<tr>
<td>Georgia</td>
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<td>254</td>
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<tr>
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<td>Indiana</td>
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<tr>
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<td>Rhode Island</td>
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<tr>
<td>South Carolina</td>
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<td>897</td>
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<tr>
<td>South Dakota</td>
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<tr>
<td>Tennessee</td>
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<tr>
<td>Texas</td>
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<td>Utah *</td>
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<td>Virginia</td>
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<tr>
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</tr>
<tr>
<td>Wisconsin</td>
<td>1,417</td>
<td>1,380</td>
</tr>
</tbody>
</table>
Wyoming | 1,907 | 1,869

* Excludes EGUs located in Indian country 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. 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 should 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 agrees that reliability must be maintained and in designing this proposed rulemaking 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 on the power system. EPA staff and managers have also had numerous discussions with state public utility commissioners and their staffs to get their suggestions and advice concerning this rule, including how to address reliability concerns.

In addition, the EPA met with independent system operators several times to discuss any potential impact of this rule on grid reliability. The ISO/RTO Council, a national organization of electric grid operators, offered analytic support to help states design programs that do not compromise the regional bulk power system. They also offered to help states develop regional approaches which may reduce costs and strengthen the reliability of the electricity grid. Specifically, the ISO/RTO Council has suggested that ISOs and RTOs could provide analytic support to help states develop and implement their plans. The ISOs and RTOs have the capability to model the system-wide effects of
individual state plans. Providing assistance in this way, they felt, would allow states with borders that fall within an ISO or RTO footprint to assess the system-wide impacts of potential state plan approaches. In addition, as the state implements its plan, ISO/RTO analytic support would allow the state to monitor the effects of its plan on the regional electricity system. ISO/RTO analytic capability could help states assure that their plans are consistent with region-wide system reliability. The ISO/RTO Council suggested that the EPA ask states to consult with the applicable ISO/RTO in developing their state plans.

The EPA has met with the U.S. 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 the BSER looked specifically at the cost effectiveness of control options in part to ensure that the options would not have a negative effect on system reliability. Each of the building blocks was determined to have reasonable costs. Further, under the Clean Air Act the states are given the flexibility to design state
plans that include any measure or combination of measures to achieve the required emission limitations. States are not required to use each of the measures that the EPA determines constitute BSER or use those measures to the same degree or extent that the EPA determines is achievable at a reasonable cost. 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 achieves the reductions necessary to meet its goal. Many market-based approaches which states may choose reduce the costs of compliance. They can allow certain units that are seldom used to remain in operation if they are needed for reliability purposes. Regional approaches also reduce costs and stress on the grid and so can help to reduce any concern about electricity reliability.

States may choose measures that would ease pressures on system reliability. This is true for many demand-side management approaches, including programs to encourage end-use energy efficiency, distributed generation, and combined heat and power, which actually reduce demand for centrally generated power and thus relieve pressure on the grid.

The EPA is proposing a 10-year period over which to achieve the full required CO₂ reductions, and we would expect this to further relieve any pressure on grid reliability. This
relatively long planning and implementation period provides states with substantial flexibility regarding methods and timing of achieving emission reductions. In addition, states can make adjustments to their implementation approaches along the way, and in doing so can consider changed conditions and whether any adjustments would help to ensure that their plans achieve the goals 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 the flows and transfers of electricity that occur to meet reserve margins. None of the interregional changes in the policy cases suggested that there would be increases in flows that would raise significant concerns about grid congestion or grid management. Moreover, the time horizon for compliance with this rule will permit environmental and reliability planners to coordinate these changes and address potential concerns before they arise.
The EPA concludes that the proposed rule will not raise significant concerns over regional resource adequacy or raise the potential for interregional grid problems. The EPA believes that any remaining local issues can be managed through standard reliability planning processes. The flexibility inherent in the rule is responsive to the CAA’s recognition that state plans for emission reduction can, and must, be consistent with a vibrant and growing economy and reliable, affordable electricity to support that economy. The EPA welcomes comments and suggestions on this issue.

### VIII. State Plans

#### A. Overview

After the EPA establishes the state-specific rate-based 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
The state must then adopt the state plan through certain procedures, which include a state hearing. Within the time period specified in the emission guidelines (from as early as June 30, 2016 to as late as June 30, 2018, depending on the state’s circumstances), the state must submit its complete state plan to the EPA. The EPA then must determine whether to approve or disapprove the plan. If a state does not submit a plan, or if the EPA does not approve a state’s plan, then the EPA must establish a plan for the state.

In the case of a tribe that has one or more affected EGUs located in its area of Indian country, as described in the Tribal Authority Rule, the tribe would have the opportunity, but not the obligation, to establish a CO2 performance standard and develop a CAA section 111(d) plan for its area of Indian country. 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 CAA section 111(d) tribal plan will actively contribute to helping reduce greenhouse gas emissions. Though the EPA is aware of three coal-fired EGUs and one natural gas-fired EGU located...
in Indian country, the agency is not proposing specific goals for areas of Indian country containing affected EGUs in this action. The EPA will coordinate with those tribes wishing to develop and implement a CAA section 111(d) tribal plan by determining BSER for the CAA section 111(d) affected units located on the tribe’s area of Indian country. As an alternative, the EPA is soliciting comment on whether tribes wishing to develop and implement a CAA section 111(d) plan should have the option of including the EGUs located on their area of Indian country in a multi-state plan (i.e., treating the tribal lands as an additional state). If a tribe chooses not to submit a plan, or if the EPA does not approve a tribe’s plan, then the EPA would need to determine if it is necessary or appropriate to establish a federal plan for affected EGUs located in Indian country.

This section is organized into six parts. First, we discuss the types of plans that we propose states could submit. Second, we address timing for plan implementation and achievement of state emission performance goals for affected EGUs. Third, we discuss the proposed state plan approvability criteria. Fourth, we summarize the proposed components of an approvable state plan. Fifth, we address the proposed process and timing for submittal of state plans. Sixth, we identify several key
considerations for states in developing and implementing plans, including: affected entities with obligations under a plan; treatment of existing state programs; incorporation of renewable energy (RE) and demand-side energy efficiency (EE) programs in certain plans; quantification, monitoring, and verification of RE and demand-side EE measures; reporting and recordkeeping for responsible parties; treatment of interstate effects; and, projecting emission performance. Finally, we discuss a number of additional factors that could help states meet their CO₂ emission performance goals, and we note certain resources that are available to facilitate plan development and implementation. Additional discussion of some of the topics covered in this section can be found in the State Plan Considerations TSD and Projecting EGU CO₂ Emission Performance in State Plans TSD, both of which are in the rulemaking docket.

B. Approach

In this action, the EPA is proposing emission guidelines in the form of state-specific CO₂ emission performance goals. In addition, the EPA is proposing guidelines for states to follow in developing plans to establish and implement CO₂ standards of performance for affected EGUs. The proposed plan guidelines include four general plan approvability criteria, twelve required components for a state plan to be approvable, the
process and timing for state plan submittal and review, and the
process and timing for demonstrating achievement of the 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 agency also anticipates – and supports – states’ commitments to a wide range of policy preferences that could encompass those of states like Kentucky, West Virginia and Wyoming seeking to continue to feature significant reliance on coal-based generation, states like Minnesota, Colorado, California and the nine RGGI states seeking to build on actions and policies they have already undertaken and states like Washington and Oregon seeking to integrate sustainable forestry and renewable energy strategies. The proposed plan guidelines provide states with options for establishing performance standards in a manner that accommodates a diverse range of state approaches. Each state will be able to determine how to best achieve the CO₂ goals in light of its specific circumstances, including addressing concerns particular to the state, such as employment transition issues, as they design and implement their
plans over multiple years. As an example, the RGGI states’ implementation of their mass-based allowance trading program featured the raising of proceeds through allowance auctions and the use of those proceeds to advance policies promoting and expanding end-use energy efficiency. States could address analogous priorities, such as employment transition, through a similar mechanism.

The proposed plan guidelines would also allow states to collaborate and to develop plans that provide for demonstration of emission performance on a multi-state basis, in recognition of the fact that electricity is transmitted across state lines, and that state measures may impact, and may be explicitly designed to reduce, regional EGU CO₂ emissions. The EPA also recognizes that multi-state collaboration would likely offer lower-cost approaches to achieving CO₂ emission reductions. With this in mind, we are proposing to provide states with additional time to submit complete plans if they do so as part of a multi-state plan, and we solicit comment on other potential mechanisms for fostering multi-state collaboration.

1. State plan approaches
   a. Overview

   We believe that different types of state CAA section 111(d) plans could be constructed that make use of the diversity of
measures that comprise the BSER.[add examples – RGGI, AB32,...].

Based on EPA’s outreach efforts, it is clear that states are considering different types of plans.

Three important issues in the design of state plans include: whether the plan should require the affected EGUs to be subject to emission limits that assure that the emissions performance level is achieved, or instead, whether the plan could rely on measures, such as renewable energy (RE) or demand-side energy-efficiency (EE), to assure the achievement of part of the emission performance level; 2) whether the responsibility for all of the measures other than emission limits should fall on the affected EGUs, or, instead, fall on entities other than affected EGUs; and 3) the fact that requiring all measures relied on to achieve the emission performance level to be included in the state plan renders those measures federally enforceable. These issues and the proposed approach are addressed in detail in the sections that follow.

The EPA is proposing that all measures relied on to achieve the emission performance level be included in the state plan, and that inclusion in the state plan renders those measures federally enforceable.

In light of current state programs, and of stakeholder expressions of concerns over those issues and legal...
considerations, the EPA is proposing to authorize states either to submit plans that hold the affected EGUs fully and solely responsible for achieving the emission performance level, or to submit plans that rely in part on measures imposed on entities other than affected EGUs to assure that at least part of that level is achieved, as well as on affected EGUs for the balance of compliance. The EPA requests comment on this approach, as opposed to the approach under which state plans simply would be required to hold the affected EGUs fully and solely responsible for achieving the emission performance level.

In addition, the EPA is soliciting comment on several other types of state plans that may assure the requisite level of emission performance without rendering certain types of measures federally enforceable and 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 fuel-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 implementation of actions that result in reduced utilization of, and therefore reduced emissions from, fossil fuel-fired EGUs, and do not impose legal responsibilities for those emission reductions on the EGUs themselves.

In addition, during the EPA’s extensive outreach efforts, many stakeholders expressed concern over the extent of responsibility that fossil fuel-fired EGUs would be required to bear for the required emission reductions, in particular, those associated with RE and demand-side EE measures. These stakeholders recommended that the EPA authorize states to achieve emission reductions from RE and demand-side EE measures by imposing requirements on entities other than fossil fuel-fired EGUs, and without imposing legal responsibility for these emission reductions on those EGUs. We request comment generally on this approach.

Accordingly, the EPA is proposing to authorize a state plan to adopt what we refer to as a “portfolio approach,” in which the plan would include emission limits for affected EGUs along with other enforceable measures, such as RE and demand-side EE measures, that reduce 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 emission reductions from, the affected EGUs. As noted, these other measures would be federally enforceable because they would be included in the state plan. A portfolio approach could be used for state plans that establish the emission performance level on either an emission rate basis or a mass emissions basis.

In addition, a portfolio approach could either be what we refer to as “utility-driven” or “state-driven,” depending on the utility regulatory structure in a state. Under a utility-driven approach, a state plan may include, for example, measures implemented consistent with a utility integrated resource plan, including both measures that directly apply to affected EGUs (e.g., repowering or retirement of one or more EGUs) as well as RE and demand-side EE measures that avoid EGU CO₂ emissions. Under a state-driven approach, the measures in a state plan

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244 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.
would include emission limits for affected EGUs, as well as requirements that apply directly to entities other than affected EGUs, for example, renewable portfolio standards or end-use energy efficiency resource standards (EERS), both of which often apply to electric distribution utilities.\(^{245}\)

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 entity or entities 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\(_2\) 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

\(^{245}\) A state-driven portfolio approach is more likely in states that have instituted electricity sector restructuring, where electric utilities have typically been required by states to divest electric generating assets.
legal issue that bears further analysis. We describe, and solicit comment on, that issue below. In brief, it may be possible to read CAA section 111(d)(1) as requiring that, when the EPA 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 emission reductions on the sources in the affected source category. Accordingly, as noted below, we are soliciting comment on whether state plans must require the affected EGUs to be legally responsible for achieving the emission performance level.

We note that some existing state programs, such as RGGI in the northeastern states, do impose the ultimate responsibility on fossil fuel-fired EGUs to achieve the required reductions, but are also designed to work either concurrently, or in an integrated fashion, with RE and demand-side EE programs that reduce the cost of meeting those emission limitations. These existing programs offer a possible precedent for another type of CAA section 111(d) state plan. Such a plan approach could rely on CO₂ emission limits enforceable against affected EGUs — whether in the form of emission rates or mass limits — to ensure
achievement of the required emission performance level, but also include enforceable or complementary RE and demand-side EE measures that lower cost and otherwise facilitate EGU emission reductions. Depending on the type of plan, these RE and demand-side EE measures could be either enforceable components of the plan or complementary to the plan. In this manner, RE and demand-side EE measures could be a major component of a state’s overall strategy for reducing EGU CO₂ emissions at a reasonable cost.

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 credit approach. (These actions would need to be enforceable components of a state plan to facilitate EGU compliance with emission rate limits and ensure that actions are properly quantified, monitored, and verified.) A state plan that imposes a mass limit
on affected EGUs that is sufficiently stringent to achieve the emission performance level would not need to include RE or demand-side EE measures as an enforceable component of the plan to assure the achievement of that performance level. The mass limit itself would suffice. However, the state may wish to implement RE and demand-side EE measures as a complement to the plan to support achievement of the mass limit at lesser cost.

d. Federal enforceability

Another concern expressed by some stakeholders is that including RE and demand-side EE measures in state plans would render those measures federally enforceable and thereby extend federal presence into areas that, to date, largely have been the exclusive preserve of the state and, in particular, state public utility commissions and the electric utility companies they regulate. These stakeholders 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 CAA section 111(d) state plan. Under those circumstances, the EGU emission limits would be federally enforceable but RE and demand-side EE measures would serve as complementary measures and would not be enforceable under federal law. Instead, they would remain enforceable under state law. According to stakeholders, those
types of state programs, particularly because they are well-established, can be expected to achieve their intended results. Thus, the states could conclude that those RE and demand-side EE measures would be beneficial in assuring the achievement of the required emission performance level by the affected EGUs specified in the CAA section 111(d) state plan, even without including those measures in the plan.

e. Plans with state commitments

As another vehicle for approving CAA section 111(d) plans for states that wish to rely on state RE and demand-side EE programs but do not wish to include those programs in their state plans, the EPA requests comment on what we refer to as a “state commitment approach.” This approach differs from the proposed portfolio approach, described above, in one major way: under the state commitment approach, the state requirements for entities other than affected EGUs would not be components of the state plan and therefore would not be federally enforceable. Instead, the state plan would include an enforceable commitment by the state itself to implement state-enforceable (but not federally enforceable) measures that would achieve a specified portion of the required emission performance on behalf of affected EGUs. The agency requests comment on the appropriateness of this approach. The agency also requests
comment on the policy ramifications of the following: under this approach, the state programs upon which the state bases its commitment may, in turn, rely on compliance by third parties, and if those state programs fail to achieve the expected emission reductions, the state could be subject to challenges—including by citizen groups—for violating CAA requirements and, as a result, could be held liable for CAA penalties.

We also solicit comment on a variation of this state commitment plan approach that is also designed to address stakeholder concerns, noted above, about imposing 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 emission performance level on the affected EGUs, but the state would credit the EGUs with the amount of emission reductions expected to be achieved from, for example, RE or demand-side EE measures. The state would then assume responsibility for that credited amount of emission reductions in the same manner as the state commitment plan approach discussed above. We solicit comment on whether, if the EPA were to conclude that CAA section 111(d) requires state plans to include standards of performance applicable to affected
EGUs that achieve the emission performance level, this type of state plan would meet that requirement while also assuring those EGUs an important measure of support.

f. Legal issues

[NOTE: PER THE ADMINISTRATOR’S REQUEST, OGC HAS EXPANDED THE DISCUSSION OF THE POSSIBLE LEGAL INTERPRETATIONS OF 111(d). OGC IS CONTINUING TO WORK ON SEVERAL ASPECTS OF THIS. FURTHER DISCUSSIONS ON TONE MAY BE NEEDED.] 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 with respect to the portfolio approach
discussed in this proposed rulemaking concern (1) whether, in addition to such emission limits on affected EGUs, state plans may include other measures for achieving the emission performance level, and (2) whether entities other than affected EGUs may be subject to requirements that contribute to reducing EGU emissions. We discuss these issues below, and, in doing so, solicit comment on possible interpretations that we could adopt as a basis for the portfolio approach.

The resolution of these issues depends in part on the threshold question of whether the phrases “standards of performance for any existing source” and “the implementation and enforcement of such standards of performance” can be read to encompass the various components of the portfolio approach. In looking at this threshold question, we solicit comment on interpreting the phrases “standards of performance” and “implementation and enforcement of such standards” in CAA section 111(d) to authorize the portfolio approach described above. CAA section 111(d) requires states to set performance standards “for” affected sources. Standards could be interpreted to be “for” fossil fuel-fired EGUs if they were to result in reduced emissions from fossil fuel-fired EGUs, even if the standards did not apply directly to fossil fuel-fired EGUs. Under this interpretation, renewable energy and demand-side
energy efficiency requirements could be standards “for” existing
EGUs. Implementation and enforcement measures could also be
interpreted to include measures such as RE and demand-side EE
that reduce emissions from fossil fuel-fired plants. We request
comment on these interpretations, as well as the following
specific issues.

First, we solicit comment on whether the definition in CAA
section 111(a)(1) could be interpreted so that standards of
performance could include measures that are not enforceable
against the affected EGUs or whether it must be interpreted so
that the standards of performance may only consist of emission
limitations on affected sources and must achieve the full degree
of emission limitation that results from application of BSER.

Second, we solicit comment on whether the requirement that
the plan include “standards of performance for [affected
sources]” could be interpreted to include the emission
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 
emission 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 
indirectly reduce 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 emission performance level through rate-based 
emission limits applicable to the affected sources, coupled with 
a crediting mechanism for RE and demand-side EE measures, 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 directly tied to emission reductions that affected sources are required to make through emission limits.

Fifth, 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.

Finally, in light of these legal issues, we solicit comment on whether, in the final rule, we should authorize different approaches in the alternative. For example, we could authorize the portfolio approach, but further provide that if legal challenges were successful, then, without the need for further notice-and-comment rulemaking by the EPA, states would be required to submit plans that achieve the emission performance level through emission limits on the affected sources. It should be noted that we consider those two approaches, as well as the other approaches for which we solicit comment, to be severable from each other.

Alternatively, the EPA acknowledges that commenters may argue that the conclusion to the threshold question is that the components of the portfolio approach are not all within the scope of “standards of performance for any existing source” and/or “the implementation and enforcement of such standards of performance.” In that case, the question becomes whether CAA...
section 111(d)(1) could be read to allow state plans to include measures that would reduce emissions from affected sources, even if those measures are neither "standards of performance for existing sources" nor measures "for the implementation and enforcement of such standards of performance." If not, must the agency interpret CAA section 111(d) to prohibit state plans from including measures that are neither standards of performance nor measures to implement or enforce them? No specific language in CAA section 111(d) prohibits states from including measures other than performance standards and implementation and enforcement measures. EPA specifically requests comment on whether there is any other basis for concluding that CAA section 111(d) allows or precludes state plans from including other measures provided that they would result in the reduction of emissions from existing sources. The EPA notes that cooperative federalism, which is one of the foundational principles of the Clean Air Act, includes providing flexibility to states to meet environmental goals (provided minimum CAA statutory requirements are met). The EPA takes comment on whether this general principle, especially when combined with the statutory directive that CAA section 111(d) regulations shall establish procedures “similar to that provided by section 110” supports an
interpretation of CAA section 111(d) that allows states sufficient flexibility in meeting CAA section 111(d) to include in their CAA section 111(d) plans other measures (i.e., measures that are neither performance standards nor measures that enforce or implement performance standards). Finally, the EPA solicits comment on all other aspects of this question concerning the scope of measures allowed in state plans under CAA section 111(d).

Notwithstanding the specific requests for comment above, the EPA solicits comment on all legal issues under CAA section 111(d)(1) with respect to the portfolio approach and the types of state plans and measures that are discussed in this preamble.

g. Ongoing applicability of CAA section 111(d) state plan

The EPA is proposing that an existing source that becomes subject to requirements under CAA section 111(d) will continue to be subject to those requirements even after it undertakes a modification or reconstruction. Under this interpretation, a modified or reconstructed source would be subject to both (1) the CAA section 111(d) requirements that it had previously been subject to and (2) the modified source or reconstructed source standard being promulgated under CAA section 111(b) simultaneously with this rulemaking. It should be noted that this proposal applies to any existing source subject to any CAA
section 111(d) plan, and not only existing sources subject to
the CAA section 111(d) plans promulgated under this rulemaking.

As noted above, a “new source” is defined under CAA section
111(a)(2) as “any stationary source, the construction or
modification of which is commenced after,” in general, a
proposed or final CAA section 111(b) rule becomes applicable to
that source; and under section 111(a)(6), an “existing source”
is defined as “any stationary source other than a new source.”
Under these definitions, an “existing source” that commences
construction of a modification or reconstruction after the EPA
has proposed or finalized a CAA section 111(b) standard of
performance applicable to it, becomes a “new source.” However,
CAA section 111(d) is silent on whether requirements imposed
under a CAA section 111(d) plan continue for a source that
ceases to be an existing source because it modifies or
reconstructs. For example, CAA section 111(d) provides that the
state plans will “establish[] standards of performance for any
existing source” but does not say whether, once a standard of
performance is established for a given source, that standard is
lifted if the source ceases to be an existing source. Similarly,
no other provisions of CAA section 111 address whether the
imposition of a CAA section 111(b) standard on a modified or
reconstructed source ends the source’s obligation to meet any applicable CAA section 111(d) requirements.

Because CAA section 111(d) does not address whether an existing source that is subject to a CAA section 111(d) program remains subject to that program even after it modifies or reconstructs, the EPA has authority to provide a reasonable interpretation, under the Supreme Court’s decision in Chevron U.S.A. Inc. v. NRDC, 467 U.S. 837, 842-844 (1984). The EPA’s interpretation is that under these circumstances, the source remains subject to the CAA section 111(d) plan, for two reasons. The first is to assure the integrity of the CAA section 111(d) plan. The EPA believes that many States will develop integrated plans that include all of their EGUs, such as rate- or mass-based trading programs. Uncertainty about whether units would remain in the program could be very disruptive to the operation of the program. The second reason is to avoid creating incentives for sources to seek to avoid their obligations under a CAA section 111(d) plan by undertaking modifications. The EPA is concerned that owners or operators of units might have incentives to modify purely because of potential discrepancies in the stringency of the two programs, which would undermine the emission reduction goals of CAA section 111(d). The EPA invites comments on this interpretation, including whether this
interpretation is supported by the statutory text and whether this interpretation is sensible policy and will further the goals of the statute.

2. Timing for implementation and achievement of goals

This section describes proposed state plan requirements related to the timing of achieving emission performance goals, including performance demonstrations, performance periods, and interim progress milestones.

As previously discussed, the goals are derived from application of four “building blocks.” The EPA has based the application of some of these measures to reduce CO₂ emissions, particularly blocks 3 (expansion of cleaner generating capacity) and 4 (increasing demand-side energy efficiency), on forward-looking, longer-term assumptions. For example, the EPA expects technologies to reduce carbon emissions to more fully develop over time and acknowledges the cumulative effects of implementation of EE programs and addition of RE generating capacity over time. Therefore, the EPA is not proposing to require each state to meet its full, final goal immediately, but rather to meet it by 2030. The EPA realizes, however, that states can achieve emission reductions from those and other measures in the short-term. Therefore, the EPA is proposing that states begin meeting interim goals, beginning in 2020. The EPA
also believes that timing flexibility in implementing measures provides significant benefits that allow states to develop plans that will help states achieve a number of goals, including: reducing cost, addressing reliability concerns, and addressing concerns about stranded assets. Therefore, the EPA is also proposing to allow states flexibility to define the trajectory of emission performance between 2020 and 2029, as long as the interim emission performance level is met on a 10-year average or cumulative basis and the 2030 emission performance level is achieved. The EPA is also proposing that states submitting complete plans by June 30, 2016 have the option to begin meeting interim goals earlier than 2020 and that the average emission performance through 2029 could reflect a higher emission rate reflective of the longer trajectory for achievement of the final CO₂ goal by 2030.

The subsections below contain proposals for: a) state plan performance demonstrations, 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. In subsection f, the agency requests comment on alternative requirements aimed at continued emission
performance improvement after 2029. **Subsection g** proposes flexibility for 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 option of alternative, less stringent state goals.

### a. Performance demonstrations

As described previously, the agency is proposing final state-specific goals (specified in Table 5) that represent emission rates **to be achieved** by 2030, as well as interim goals, **to be achieved** on average over the 10-year period from 2020-2029. The agency is also proposing that emission performance levels consistent with the final state-specific goals be maintained **after** 2030.

This relatively long planning and implementation period provides states with substantial flexibility regarding methods and timing of achieving emission reductions. States may wish to make adjustments to their implementation approaches along the way, or as conditions change may need to make adjustments to ensure that their plans achieve the goals as intended. As a result, the agency envisions that the EPA, states, and regulated entities will have an ongoing relationship in the course of implementing this program.
The EPA proposes that a state plan must demonstrate projected achievement of the emission performance levels in the plan, and these emission performance levels must be equivalent to or better than the interim and final goals established by the EPA. Specifically, the state plan must demonstrate that the projected emission performance level of affected EGUs in the state will be equivalent to or better than the applicable interim goal during the 2020-2029 period, and equivalent to or better than the applicable final goal during the year 2030. The state plan must identify requirements that continue to apply after 2030 and are likely to maintain continued emission performance by affected EGUs that meets the final goal; however, quantitative projections of emission performance by affected EGUs beyond 2030 would not be required. Instead, the EPA proposes that the state plan would be considered to provide for maintenance of emission performance consistent with the final goal if the plan measures used to demonstrate achievement of the final goal by 2030 will continue in force and not sunset.

In addition to demonstrating that projected plan performance will meet the interim and final state goals, the EPA proposes that state plans must contain requirements for tracking actual plan performance during implementation. For plans that do not include enforceable requirements for affected EGUs that
ensure achievement of the full level of required emission performance and interim progress, the state plan would be required to include periodic program implementation milestones and emission performance checks, and include corrective measures to be implemented if mid-course corrections are necessary. The state plan would provide for continued tracking of emission performance after 2030, and for corrective measures if the emission performance of affected EGUs in the state did not continue to meet the 2030 final goal during any three-year performance period.

The rationale for this approach is that it would ensure that states design their plans in a way that considers both the interim and final goals. If only the interim goal were considered, a state plan might not be sufficient to achieve the final goal.

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 emission 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.

\[247\]
The agency requests comment on a second option in which, in addition to submitting a plan demonstrating emission performance over the 2020-2030 period, states would be required to make a second submittal in 2025 showing whether their plan measures would maintain the final-goal level of emission performance over time (under one of the out-year approaches described in the relevant section below). If not, the state submittal would be required to strengthen or add to measures in the state plan to the extent necessary to maintain that level of performance over time.

The EPA also requests comment on whether 2025, or an earlier or later year, would be the optimal year for a second plan submittal under the second option.

b. Start date for performance period for interim goal

A performance period is a period for which the state plan must demonstrate that the required emission performance level will be met. The EPA proposes a start date of January 2020 for the interim goal plan performance period. The agency generally requests comment on the appropriate start date and rationale.

248 The start date for a plan performance period must match the start date of the corresponding state emission performance goal. If a start date other than January 2020 were selected, the EPA would recompute the state goals consistent with the selected start date.
In considering the start date, it is relevant to consider the due dates for state plan submittals and the amount of time available for program implementation by the start date. January 2020 is 3.5 years from the proposed June 2016 deadline for initial plan submittals, 2.5 years from the proposed June 2017 extended deadline for complete plans from states not participating in a multi-state plan, and 1.5 years from the proposed June 2018 extended deadline for complete plans from states participating in a multi-state plan. The EPA suggests that affected entities may have greater lead time for compliance than might be implied by the plan submittal dates referenced above. Affected entities will have knowledge of state requirements as they are adopted, and the state must adopt rules and requirements in advance of submitting its complete plan to the EPA. Also, as explained in detail in subsection c, states may choose a different emission performance improvement trajectory from that which the EPA assumes for purposes of calculating state goals, achieving lesser levels of performance in early years and more in later years.

The EPA proposes that a 2020 start date for the interim goal plan performance period is achievable in light of the following additional considerations. First, existing state programs will play a role in helping to achieve this rule’s
proposed emission performance levels. Second, in advance of this proposal, many states already were contemplating design of strategies that would achieve CO₂ reductions equivalent to those that could be required by CAA section 111(d) emission guidelines. Third, for inclusion in the building blocks, the EPA considered only those emission abatement measures that are technically feasible and broadly applicable, and can provide reductions in CO₂ emissions from affected EGUs at reasonable cost.

For example, the EPA expects that many EGUs will meet their requirements in part by implementing heat rate improvements, and those actions may be undertaken promptly. The plant operations and maintenance (O&M) and 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 HRI methods and can be applied quickly, without lengthy EGU outages. The somewhat more costly HRI “upgrades” (e.g., steam...
turbine upgrade, boiler draft fan/driver upgrade) may require modest EGU outages to implement, but have also been applied on numerous EGUs to improve or maintain performance. Drawing on the power sector’s extensive experience with HRI methods, and the many existing supply chains already supporting these methods, the EPA expects that it would be feasible to implement HRI projects (i.e., building block 1) by 2020.

Dispatch changes, which are largely driven by the variable cost of operating a given EGU, occur on an hourly basis in the power sector. The average availability factor for NGCCs in the U.S. generally exceeds 85 percent, and can exceed 90 percent for selected groups. 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.

\[249\] Source: NERC, 2008-2012 Generating Unit Statistical Brochure
Building Block 3 is based on shifting generation from affected fossil units to new renewable energy generating capacity, which is added over time, and new or preserved nuclear capacity, all of which is expected to be in place by 2020 (see the GHG Abatement Measures TSD for more information).

Finally, there is considerable experience with the states and the power sector in designing and implementing demand-side energy efficiency improvement strategies and programs. It is also well accepted that such improvements can achieve reductions in CO₂ emissions from existing EGUs at a reasonable cost. Building block 4 represents a feasible pathway for reducing utilization of carbon-emitting EGUs by implementing improvements in demand-side energy efficiency. This building block is based on a “best practices” scenario where all states achieve a level of performance - matching a level achieved or committed to by twelve leading states - of 1.5 percent annual incremental electricity savings as a percentage of retail sales. For the best practices scenario, all states achieve this level of performance no later than 2025, with leading states reaching this level sooner. Each state’s current level of performance is taken into account, with states achieving lower levels of performance being allowed more time to reach the best practice level.
c. Duration of performance periods for final and interim goals

The EPA recognizes that a state’s circumstances and choice of emission reduction strategies may affect the timing of 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 emission reduction measures and programs (e.g., heat rate improvements) are generally easier to implement in the near term, while others (e.g., renewable portfolio standards, demand-side energy efficiency programs) may require several years to implement because of the time necessary to establish the proper infrastructure if a state does not already have such programs in place. Though some states have already implemented such programs that are achieving results, other states may have to establish them for the first time. New single and multi-state programs, as well as existing single and multi-state programs that are adding or revising measures, may need time for implementation to achieve the required level of emission performance.

As described in Section VII of the preamble, the EPA is proposing state-specific CO₂ emission performance goals in a multi-year format to provide states with flexibility for the timing of programs and measures that improve EGU emission...
performance, while ensuring an overall level of performance consistent with 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 to be achieved on average over the 2020-2029 period (the interim goal).

The EPA proposes the following as the preferred option for the final and interim goal performance periods. As further explained below, this option reflects three main objectives: (1) provide states with timing flexibility during the interim goal period to accommodate differences in state adoption processes and types of state programs, (2) ensure that state plans are designed to achieve the final goal no later than 2030, and (3) provide flexibility for year-to-year variation in actual emission performance that may occur as the electricity system responds to economic fluctuations.

Interim goal – Projected plan performance demonstration: To be approvable, a state plan must demonstrate that the emission performance of affected EGUs will meet the interim emission performance level on average over the 2020-2029 period.

Interim goal – Actual plan performance check: In 2030, the emission performance of affected EGUs during the period 2020-2029 must be compared against the interim goal. (In addition, as similarly, the EPA proposes that plan measures initially achieve the final...
described separately below, interim emission performance checks will occur during this 10-year period.)

Final goal – Projected plan performance demonstration: To be approvable, a state plan must demonstrate that the emission performance of affected EGUs will meet the final emission performance level no later than 2030, on a single-year basis.

Final goal – Actual plan performance check: Starting at the end of 2032, emission performance of affected EGUs must be compared against the final goal on a three-year rolling average basis (i.e., 2030-32, 2031-33, 2032-2034, etc.).

This proposed approach provides a 10-year performance period for the interim performance level. The 10-year period allows states flexibility for timing of program implementation as the state ramps up its programs to achieve the final performance level. Using the single year 2030 as the projected year for achievement of the final goal ensures that state plans are designed to achieve the final goal no later than 2030; providing a multi-year time frame for projected plan performance would inappropriately delay the requirement for a final-goal level of performance that the EPA’s analysis shows is achievable at the end of the 10-year interim ramp-up period. Using 2030 also avoids overlap with the interim goal performance period. The rolling three-year performance periods for measuring actual
plan performance against the final goal performance level are proposed in light of year-to-year variability in economic and other factors, such as weather, that influence power system operation and affect EGU CO\(_2\) emissions. The choice of 2030-2032 avoids overlap with the 2020-2029 interim goal performance period.

For a rate-based plan, 2020-2029 emission performance is an average CO\(_2\) emission rate for affected EGUs representing cumulative CO\(_2\) emissions for affected EGUs over the course of the 10-year performance period divided by cumulative MWh energy output\(^{250}\) 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 CO\(_2\) emitted by affected EGUs over the 10-year performance period.

The EPA also requests comment on a second approach to state plan performance periods. Under this approach, in addition to the requirements the proposal, a state plan also would also need to achieve a five-year average emission performance level reflecting application of BSER for the 2020-2024 period. This

\(^{250}\) 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.
A five-year performance period would nest within the 10-year performance period for the 2020-2029 period. The purpose of this approach would be to ensure greater emission performance improvement during the first five years of the interim goal plan performance period by precluding states from significantly delaying compliance obligations until the last five years. However, this approach 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 plans.

d. Program implementation milestones and tracking of emission performance

The EPA recognizes the importance of ensuring that, during the proposed 10-year performance period (2020-2029) for the interim goal, a state is making steady progress toward achieving the required level of emission performance. The EPA is proposing that certain types of state plans be required to have programmatic implementation milestones to ensure interim progress, as well as periodic checks on overall emission performance leading to corrective measures if necessary.

Some types of plans are “self-correcting” in that they inherently would assure interim performance and full achievement of the state plan’s required level of emission performance.
through requirements that are enforceable against affected EGUs. One example is a state plan with a rate-based emission performance level that requires affected EGUs collectively to meet, on a three-year average basis, an emission rate consistent with the state’s required emission performance level, and allows EGUs to comply through an emission rate averaging system. Another example is a plan that includes measures or actions (e.g., emission limits that apply to affected EGUs and ensure full plan performance) that take effect automatically if the plan’s required emission performance level is not met, in accordance with a specified milestone. The EPA requests comment on whether there are other types of state plans that should be considered “self-correcting.”

The EPA proposes that self-correcting plans need not contain interim milestones consisting of program implementation steps, because these state plans inherently require both interim progress and achievement of the full level of required emission performance in a manner that is federally enforceable against affected EGUs.

For plans that are not self-correcting, the EPA proposes that the state plan must identify periodic program implementation milestones (e.g., start of an end-use energy efficiency program, retirement of an affected EGU, or increase
in portfolio requirements under a renewable portfolio standard) that are appropriate to the programs and measures included in the plan. If, during plan implementation, a state were to miss program implementation milestones in its plan, it would need to report the delay to EPA, explain the cause, and describe the steps the state will take to accelerate subsequent implementation to achieve the planned improvements in emission performance. Depending on the severity of delay and the explanation, the EPA could ultimately evaluate actions under CAA authorities to ensure timely program implementation.

In addition, we propose that the state and the EPA would track state plan emission performance on an ongoing basis, with states reporting performance data to EPA annually by July 1. During the interim performance period, the state would be required to include a comparison of emission performance achieved to performance projected in the state plan each year from the end of 2022 through the end of 2028. Each comparison would cover the preceding two-year period. The EPA may also approve regular, periodic emission comparison checks with a different frequency or comparison period to reflect the design of a state’s programs (e.g., compliance periods for EGUs under an emission limit).
If actual emission performance of affected EGU was not within 10 percent of plan projections, the state would be required in its submission to explain reasons for the deviation (e.g., energy efficiency program not working as effectively as expected, prolonged extreme weather that had been unanticipated in electricity demand projections) and specify the corrective measures that will be taken to ensure that the required level of emission performance in the plan will be met. The state also would be required to implement those corrective measures as expeditiously as practical.

The EPA proposes that the corrective measures to be triggered in case of an emission performance deficiency must be adopted as enforceable measures included in the original state plan. These previously adopted corrective measures would reduce the delay between the time an emission performance deficiency is discovered, and the time that corrective action can begin. Alternatively, the agency requests comment on whether states should be allowed to identify and adopt corrective measures after a performance deficiency is found.

At the end of the 2020-2029 performance period, the EPA proposes that the state be required to compare actual emission performance achieved during the performance period against the interim goal. As noted above, beginning after 2032, EPA proposes
that the state be required to compare actual emission performance achieved against the final goal on a rolling three-year average basis (e.g., 2030-32, 2031-33, etc.).

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

e. Consequences if actual emission performance does not meet state goal

There are scenarios under which an approved state plan might fail to achieve a level of emission performance by affected EGUs that meets the state goal. Under some types of plans, a possible scenario is that despite successful plan implementation, emissions under the plan turn out to be higher than projected at the time of plan approval because actual economic conditions vary from economic assumptions used when projecting emission performance. State officials have raised the possibility that achieved emission performance might not meet projected performance if, for example, planned retirements of EGUs were postponed because severe weather produced greater-than-expected electricity generation needs. In addition, emissions could theoretically exceed projections because affected entities under a state plan did not fulfill their
responsibilities, or because the state did not fulfill its responsibilities.

The EPA believes that the emission guidelines should specify the consequences in the event that actual emission performance under a state plan does not meet the applicable interim goal in 2020-2029, or does not meet the applicable final goal in 2030-2032 or later, because CAA section 111(d) is not specific on this point. The agency requests comment on how the consequences should vary depending on the reasons for a deficiency in performance.

Specifically, the agency requests comment on whether consequences should include the triggering of corrective measures in the state plan, or plan revisions to adjust requirements or add new measures. The agency also requests comment on whether corrective measures, in addition to ensuring future achievement of the state goal, should be required to achieve additional emission reductions to offset any emission performance deficiency that occurred during a performance period for the interim or final goal. This concept has been applied, for example, in the acid rain sulfur dioxide program; a source that has sulfur dioxide emissions exceeding the emission allowances that it holds at the end of the period for demonstrating compliance is required subsequently to obtain
additional emission reductions to offset its excess emissions. The agency also requests comment on the process for invoking requirements for implementation of corrective measures in response to a state plan performance deficiency.

The EPA further requests comment on whether the agency should promulgate a mechanism under CAA section 111(d) similar to the SIP call mechanism in CAA section 110. Under this approach, after the agency made a finding of the plan's failure to achieve the state goal during a performance period, EPA would require the state to cure the deficiency with a new plan within a specified period of time (e.g., 18 months). If the state still lacked an approved plan by the end of that time period, the EPA would have the authority to promulgate a federal plan under section 111(d)(2)(A).

f. 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 emission performance should only be maintained -- or instead should be further improved -- once the final goal is met in 2030. This involves questions of goal-setting as well as questions about state planning. In this section, the EPA
proposes that a state must maintain the required level of performance, and requests comment on the alternative of requiring continued improvement.

The EPA believes that Congress intended the emission performance improvements required under CAA section 111(d) to be permanent. Other CAA section 111(d) emission guidelines set emission limits to be met permanently. Therefore, the EPA is proposing that the level of emission performance for affected EGUs represented by the final goal should continue to be maintained in the years after 2030. The EPA is proposing a mechanism for implementing this objective, and is taking comment on an alternative option.

As noted above, the EPA proposes that the state plan must demonstrate that plan measures are projected to achieve the final emission performance level by 2030. In addition, the state plan must identify requirements that continue to apply after 2030 and are likely to maintain affected EGU emission performance meeting the final goal; however, quantitative projections of emission performance beyond 2030 would not be required under the proposed option. Instead, EPA proposes that the state plan would be considered to provide for maintenance of emission performance consistent with the final goal if the plan measures used to demonstrate projected achievement of the final
goal by 2030 will continue in force and not sunset. After implementation, the state would be required to compare actual plan performance against the final goal on a rolling three-year average basis starting in 2030, and to implement corrective measures if necessary.

The EPA also requests comment on an alternative approach to a state’s pre-implementation demonstration that the final-goal level of performance will be maintained after 2030. Under this alternative, the state plan would be required to include projections demonstrating that emission performance would continue to meet the final goal for up to 10 years beyond 2030). This approach could be implemented through a second round of state plan analysis and submittals in 2025, to make the demonstration and strengthen or add measures if necessary. The EPA generally requests comment on appropriate requirements to

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251 This is straightforward for plans with EGU emission limits that ensure the full level of performance required. For renewable energy programs, the agency suggests that the state could continue to require the renewable portfolio percentage level that was relied upon to demonstrate projected achievement of the final goal performance level in 2030. For plans that rely in part on end-use energy efficiency programs and measures, the EPA requests comment on what a state would need to require in its plan to show that performance will be maintained after 2030. End-use energy efficiency programs and measures often involve an annual energy savings requirement or goal, and some types require additional monetary expenditures each year to meet those savings requirements or goals.
maintain the emission performance of affected EGUs in years after 2030.

The EPA also requests comment on whether we should establish BSER-based state emission performance goals for affected EGUs that extend further into the future (e.g., beyond the proposed planning period), and if so, what those levels of improved performance should be. Under this alternative, the EPA would apply its goal-setting methodology based on application of BSER in 2030 and beyond to a specified time period and final date. The agency requests comment on the appropriate time period(s) and final year for the EPA’s calculation of state goals that reflect application of BSER under this approach.

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

The EPA proposes that states have flexibility to choose between a rate-based and mass-based performance level for each performance period. For example, if a state plan used a mass-based performance level for the 2020-2029 period, the state plan may still use a rate-based performance level for final goal performance periods, or vice versa.

A state that adopted a mass-based performance level for 2020-2029 would have two options for addressing any perceived need for emissions flexibility in light of anticipated economic
growth after 2029. The state either could adopt a rate-based performance level consistent with the final goal, or could adopt a new mass-based performance level based on a translation of the rate-based final goal to a mass-based goal.

h. Planning approach for alternative state goals

In Section VII, the EPA requests comment on alternative, five-year state emission performance goals for affected EGUs shown in Table 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 another approach for state plan performance periods. This approach would require state plans to demonstrate that the required interim emission performance level will be met on average by affected EGUs during the five-year 2020-2024 interim period, and that the alternative final goal be met no later than 2025. After plan implementation, actual emission performance would be compared with the alternative final goal on a three-year rolling average basis, starting with 2025-2027, in light of year-to-year variability in economic and other factors, such as...
weather, that influence power system operation and affect EGU CO₂ emissions.

In connection with the alternative state goals, for the years after 2027, the EPA requests comment on the same “out-year” issues and concepts for maintaining or improving emission performance over time that are described above in subsection e. The EPA requests comment on whether state plans should provide for emission performance after 2025 solely through post-implementation emission checks that do not require a second plan submittal, or a whether states should also be required to make a second submittal prior to 2025 to demonstrate that its programs and measures are sufficient to maintain performance meeting the final goal for at least 10 years. In addition, the agency requests comment on the appropriate date for any second state plan submittal designed to maintain emission performance after the 2025 performance level is achieved.

C. Criteria for Approving State Plans

The EPA is proposing to require the twelve plan components discussed in Section VIII.D of this preamble. We will evaluate the sufficiency of each plan based on the plan addressing those components and on four general criteria for a state plan to be approvable. First, a state plan must contain enforceable measures that reduce EGU CO₂ emissions. Second, these enforceable

**Deleted:** This demonstration would be required as part of the same plan submittal that addresses 2020-2024 emission performance.

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measures must be projected to achieve emission performance equivalent to the applicable state-specific CO₂ goal on a timeline equivalent to that in the emission guidelines. ²⁵² 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 entity), CO₂ emission performance outcomes, and implementation of corrective actions, if necessary. The EPA requests comments on all aspects of these general criteria and the ten specific plan components described below.

The agency also notes that a CAA section 111(d) state plan is not a CAA section 110 state implementation plan (SIP). Although there are similarities in the two programs, approvability criteria for CAA section 111(d) plans need not be identical to approvability criteria for SIPs.

1. Enforceable measures

In developing its plan, to ensure that the plan is enforceable and in conformance with the CAA, a state should follow established EPA guidance on enforceability. ²⁵³ This

²⁵² Flexibilities provided to states in meeting this general approvability criterion are discussed below in Section VIII.B.2., emission performance.
²⁵³ Enforceability guidance includes: (1) September 23, 1987 memorandum and accompanying implementing guidance, “Review of State Implementation Plans and Revisions for Enforceability and
guidance serves as the foundation for the types of emission limits that the EPA has found can be enforced as a practical matter and sets forth the general principle that a requirement that is enforceable as a practical matter is one that is quantifiable, verifiable, straightforward, and calculated over as short a term as reasonable.

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 proposing that a state plan may take a portfolio approach, which could include enforceable CO₂ emission limits that apply to affected EGUs as well as other enforceable measures, such as RE and demand-side EE measures, that avoid EGU CO₂ emissions, and are implemented by the state or by another entity assigned responsibility by the state. As noted above, we are proposing that state plans are not required to impose emission limits on affected EGUs that in themselves fully achieve the emission performance level. However, we are seeking comment on whether, for state plans where emission limits applicable to affected EGUs alone would not assure full

achievement of the required level of emission performance, the state plan 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.254

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 considerations under different state plan approaches, which is addressed below in VIII.F.

2. Emission performance

The second criterion for approvability is that the projected CO₂ 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 CO₂ emission performance level in

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254 This could include, for example, an expansion of the scope or an increase in stringency of the current measures in the plan, a second set of measures that avoid EGU CO₂ emissions, or emissions limits that apply to affected EGUs.
the state plan. State plans that are projected to achieve an average CO₂ emission rate (expressed in, for example, lb CO₂/MWh) or tonnage CO₂ emission outcome by all affected EGUs equal to, or lower than, the required level of CO₂ emission performance in the plan would meet this approvability criterion.

We are proposing that states may demonstrate such emission performance by affected EGUs either on an individual state basis or jointly on a multi-state basis. All of the emission reduction measures included in the agency’s determination of BSER reduce CO₂ emissions from affected EGUs. As a result, the EPA is not proposing that out-of-sector GHG offsets could be applied to demonstrated CO₂ emission performance by affected EGUs in a state plan.

However, states could still include in their plans emission limits for affected EGUs that include the ability to use GHG offsets for compliance, provided those emission limits would achieve the required level of emission performance in a state plan. All existing state emission budget trading programs addressing GHG emissions include out-of-sector project-based emission offsets, which may be used to cover a portion of the compliance obligation of affected sources. Other states may want to take a similar approach, for example, to incentivize GHG emission reductions from land use and agricultural waste.
How to address GHG offsets included in EGU emission limits when projecting emission performance under a state plan is addressed in the Projecting EGU CO₂ Emission Performance in State Plans TSD.

The ISO/RTO Council, an organization of electric grid operators, has suggested that ISOs and RTOs could play a facilitative role in developing and implementing region-wide, multi-state plans, or coordinated individual state plans. Existing ISOs and RTOs 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.  

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) 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 a multi-year plan performance period if emission performance is not met, or at

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255 Considerations for quantification, monitoring, and verification of RE and demand-side EE measures are addressed in Section VII.E of this preamble and in the State Plan Considerations TSD.
specified interim stages within a multi-year plan performance 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.F.

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

D. State Plan Components

The EPA is proposing that an approvable plan must meet the approvability criteria described above and include the twelve state plan components summarized below, consistent with additional specific requirements explained elsewhere in this notice. Plans must comply with the EPA framework regulations at 40 C.F.R. 60.23-60.29, except as specified otherwise by these emission guidelines. These requirements apply both to individual state plans and multi-state plans.
For states wishing to participate in a multi-state plan, the EPA is proposing that only one multi-state plan would be submitted on behalf of all participating states. The joint submittal would be signed by authorized officials for each of the states participating in the multi-state plan and would have the same legal effect as an individual submittal for each participating state. The joint submittal would adequately address plan components that apply jointly for all participating states and for each individual state in the multi-state plan, including necessary state legal authority to implement the plan, such as state regulations and statutes. Because the multi-state plan functions as a single plan, each of the required plan components described below (e.g., plan performance levels, program implementation milestones, emission performance checks, and reporting) would be designed and implemented by the participating states on a multi-state basis.

The EPA proposes that each plan must have 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 identify any other affected entities 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 the state 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 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.

The EPA is proposing that multiple states could jointly demonstrate emission performance by affected EGUs. For these multi-state approaches, states would demonstrate emission performance by affected EGUs in aggregate with partner states. For states participating in a multi-state approach, the individual state performance goals in the emission guidelines would be replaced with an equivalent multi-state performance goal. For example, states taking a rate-based approach would demonstrate that all affected EGUs subject to the multi-state plan achieve a weighted average CO₂ emission rate that is consistent, in aggregate, with an aggregation of the state-specific rate-based CO₂ emission performance goals established in the emission guidelines that apply to each of the participating states. If states were taking a mass-based approach, participating states would demonstrate that all affected EGUs subject to the multi-state plan emit a total tonnage of CO₂ emissions consistent with a translated multi-state mass-based goal. This multi-state mass-based goal would be based on translation of an aggregation of the state-specific rate-based
The EPA is seeking comment on two options for calculating a weighted average rate-based CO₂ emission performance goal for multiple states. Under the first option, the weighted average emission rate goal for a group of participating states is computed using each state’s emission rate goal from the emission guidelines and the quantity of electricity generation by affected EGUs in each of those states during the 2012 base year that the EPA used in calculating the state-specific goals. Different levels would be computed for the interim and final goals. This approach is consistent with the method used to calculate the state-specific rate-based emission performance goals. However, it does not address the fact that the weighted average emission rate performance goal for multiple states may be influenced significantly by the weighting of electricity generation from affected EGUs in different states. This mix of generation among affected EGUs in different states could differ significantly during the plan performance periods from that during the 2012 base year.

Under the second option, the weighted average emission rate goal for a group of participating states is computed using each state-specific emission rate goal and the quantity of projected
electricity generation by affected EGUs in each state. The calculation would be performed for the 2020 through 2029 period to produce a multi-state interim goal, and for 2030 to produce a multi-state final goal. This projection of electricity generation by affected EGUs would be for a reference case that does not include application of either the state-specific rate-based emission performance goals for the participating states or the requirements, programs, and measures included in the multi-state plan. This approach addresses the fact that the mix of generation among affected EGUs in different states could differ significantly during the plan performance periods from that during the 2012 base year. As a result, it would base the weighted average goal in part on the anticipated business-as-usual mix of generation by affected EGUs across the multiple states during the plan performance period. However, this approach could also significantly alter the weighted average performance goal based on projected retirements of affected EGUs in one or more states.

Under both options, the rate-based multi-state goal could be translated to a mass-based goal. These options, and the procedure for translation to a mass-based goal, are discussed in more detail in the Projecting EGU CO₂ Emission Performance in State Plans TSD.
We are requesting comment on whether, to assist states that seek to translate the rate-based goal into a mass-based goal, the EPA should provide a presumptive translation of rate-based goals to mass-based goals for all states, for those who request it, and/or for multi-state regions. As another alternative, the EPA could provide guidance for states to use in translating a rate-based goal to a mass-based goal for individual states and for multi-state regions. This could include information about acceptable analytical methods and tools, as well as default input assumptions for key parameters that will likely influence projections, such as electricity load forecasts and projected fossil fuel prices. Under this approach, the EPA might also provide a coordinating function in addressing the assumptions applied by multiple states within a grid region, acknowledging that assumptions about state programs across a broader grid region that are included in an analysis scenario 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 EGU CO₂ Emission Performance in State Plans TSD. The TSD includes a discussion of possible acceptable analytical methods, tools, and key assumption inputs that will influence projections. The agency invites comment on these technical considerations.

4. Demonstration that the plan is projected to achieve the state’s emission performance level

A state plan must demonstrate that the actions taken pursuant to the plan are, when taken together, projected to achieve the state’s emission performance level within the plan performance period. This demonstration will include a detailed description of the analytic process, tools and assumptions used to project future CO₂ emission performance by affected EGUs under the plan and the results of the analysis.

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 emission performance in a manner that is federally enforceable against affected EGUs). These programmatic milestones with specific dates for...
achievement should be appropriate to the programs and measures included in the plan.

In addition, the state plan demonstration will indicate the plan’s intended trajectory of emission performance improvement. As described in Section VIII.A.2.d., no less than every two years, beginning January 1, 2022, the state must compare emission performance achieved by affected EGUs in the state with performance projected in the state plan. If actual emission performance is not within 10 percent of original projections, the state must submit a report by 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. Corrective measures

For a plan that does not include self-correcting mechanisms, the plan must also specify corrective measures that have been or will be implemented if the state’s progress in achieving its level of performance for affected EGUs falls short of what is projected under the plan, as well as a process and schedule for implementing any such measures. The agency requests comment on the amount of emission rate improvement or emission reduction that the corrective measures included in the plan must
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 January 2014 proposed Carbon Pollution Standards, 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 rate-based standard of performance for affected EGUs and/or other affected entities subject to a state plan is no longer than 12 months within the plan period and no longer than three years for a mass-based standard. We also solicit comment on longer and shorter averaging times for a standard of performance included in a state plan. 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, non-duplicative, 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.256 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

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calculated over as short a term as reasonable. As reflected in section VIII.F.2.c.4 of this preamble, the EPA recognizes that states have a diversity of experiences with RE and demand-side EE measures, and we are seeking comment on whether the EPA should establish further guidance on the quantification, monitoring and verification of such measures.

For each standard of performance, a plan must describe how it is quantifiable, non-duplicative, 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, in a manner that can be replicated. These issues are discussed further in Section VIII.F.4 and in the State Plan Considerations TSD. A standard of performance is non-duplicative with respect to an affected entity if it is not already incorporated in another state plan, except in instances where incorporated in another state as part of a multi-state plan. An example of a duplicative standard of performance would occur where recognition of avoided CO2 emissions from, for example, a wind farm, could be applied in more than one state’s CAA section 111(d) plan, except in the case of a multi-state plan where recognition is assigned among states or emission performance is demonstrated jointly for all affected EGUs subject to the multi-state plan. This does not
mean that measures in a standard of performance cannot also be used for other purposes. For example, if a state wished to take credit for CO\textsubscript{2} emissions avoided due to electric generation from a new wind farm, those avoided emissions could be considered non-duplicative and included for purposes of CAA section 111(d), even if electric generation from that wind farm was also being used to generate renewable energy certificates (RECs) to comply with the state’s RPS requirements. It also does not mean that a single affected entity could not be subject to similar standards of performance in different state plans. For example, an affected entity might be an electric distribution utility that has a service territory that crosses state lines. This entity might be subject to a separate state demand-side EE requirement for electricity supplied in each of the states where it serves electricity customers. In this instance, the same company could be an affected entity subject to a different state demand-side EE requirement in each state plan, without these standards of performance in each plan being considered duplicative. The EPA solicits comment on whether an emission reduction becomes duplicative (and therefore cannot be used for demonstrating performance in a plan) if it is used as part of another state’s demonstration of emission performance under its CAA section 111(d) plan.
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 requirements are in place to enable the state and the Administrator to independently evaluate, measure, and verify compliance with it. This is discussed further in Section VIII.F.4 and in the State Plan Considerations TSD. 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 CAA.
9. Identification of monitoring, reporting, and recordkeeping requirements

The state plan must describe the CO₂ emission monitoring, reporting, and recordkeeping requirements for affected EGUs, including requirements for monitoring and reporting of useful energy output if a state plan is taking a rate-based approach. The EPA is proposing that each plan include monitoring, reporting, and recordkeeping requirements for 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.

Most affected EGUs already monitor CO₂ emissions under 40 CFR Part 75 and report the data using the EPA’s Emission Collection and Monitoring Plan System (ECMPS), which would generally satisfy CO₂ reporting requirements under the proposed guidelines. However, we are seeking comment on two possible adjustments to the Part 75 Relative Accuracy Test Audit (RATA) requirements for steam EGU stack gas flow monitors that can affect reported CO₂ emissions. The first possible adjustment...
would be to require use of the most accurate RATA reference method for specific stack configurations, while the second possible adjustment would be to require a computation adjustment when an EGU changes RATA reference methods. The rationale for these possible adjustments is described further in the Part 75 Monitoring and Reporting Considerations TSD available in the docket.

We are also proposing monitoring and reporting protocols for net energy output under 40 CFR Part 75 that would allow the ECMPS to be used for purposes of meeting the net energy output reporting requirement. 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.257) 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 energy output.

257 70 FR 1429-1519; January 8, 2014.
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 TSD mentioned above.) 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. This is discussed further in Section VIII.F.4 and the State Plan Considerations TSD.

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 must provide certification that a hearing on the state plan was held, a list of witnesses and their organizational affiliations, if any, appearing at the hearing, and a brief written summary of each presentation or written submission pursuant to the requirements of the EPA framework regulations at 40 CFR 60.23.

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 part of 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 **must** also provide analytical materials used in translating a rate-based goal to a mass-based goal (if a translation is included), analytical materials used in projecting emission performance that will be achieved through the plan, relevant implementation materials, and any additional technical requirements and guidance the state proposes to use to implement elements of the plan.

E. Process for State Plan Submittal and Review

1. Overview

   Under the framework regulations, state plans would be due nine months after finalization of the emission guidelines. 40 CFR 60.23(a)(1). During the outreach process, many states expressed concern that this was not sufficient time to prepare and submit a state plan to the EPA. States commented that additional time was needed to accommodate, among other things, state legislative and rulemaking schedules, coordination among states involved in multi-state plans, coordination with third parties, and the complex technical work needed to develop a state plan. The EPA recognizes that state administrative procedures can be lengthy, some states may need new legislative authority, and that states planning to join in a multi-state...
plan will likely need more than thirteen months to get necessary elements in place. Balanced against that concern, however, is the urgency of addressing carbon emissions and the fact that there are certain steps we believe states can take within thirteen months to set themselves on a clear path to adoption of a complete plan. Therefore, the EPA is proposing a plan submittal process with a submittal date of June 30, 2016 (thirteen months after the expected finalization date of the emission guidelines), that provides additional time to submit a complete plan to the EPA after June 30, 2016, when justified. Part of that justification would include the state’s demonstration of having taken meaningful steps during the first thirteen months toward implementing a complete plan. This approach involves the option that we refer to as an initial submittal, followed by submittal of a complete state plan no later than either June 30, 2017 for single-state plans or June 30, 2018 for multi-state plans.

In addition, for states wishing to participate in a multi-state plan, the EPA is proposing that only one multi-state plan would be submitted on behalf of all participating states, provided it is signed by authorized officials for each of the states participating in the multi-state plan and contains the necessary regulations, laws, etc. for each state in the multi-
state plan. In this instance, the joint submittal would have the same legal effect as an individual submittal for each participating state.

2. State plan submittal and timing

The EPA framework regulations (40 CFR 60.23) require that state plans be submitted to the EPA within nine months of promulgation of the emission guidelines, unless EPA specifies otherwise. In view of the complexity of these plans, we are proposing to extend 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 the 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 plan submittal by June 30, 2016.

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258 40 CFR 60.23(a)(1).
The EPA will respond to a state’s notice that it intends to request an extension of the plan submittal date within 45 days through a letter response. The EPA will acknowledge receipt of the state’s April notice and advise the state whether the outline of actions the state is currently undertaking to develop a plan indicate that the state is on track to submit an approvable initial submittal. The EPA’s response to the state’s April notice letter will be advisory only and will not constitute final agency action. The EPA will act to approve or disapprove a state’s request for a date extension in response to the state’s initial submittal.

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 should not consider as warranting 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 plan guidelines, then the EPA will notify the state by letter, within 60 days, that it has received the initial state plan and determine whether it meets the minimum requirements. The EPA’s letter acting on the initial submittal will specify whether the new due date for the state’s complete plan is June 30, 2017 or June 30, 2018. The EPA believes this approach is authorized by, and consistent with, section 60.27(a) of the implementing regulations.

If the EPA approves a two-year extension to June 30, 2018, for a state developing a multi-state plan, the state would be required to provide one update, on June 30, 2017, on its progress toward milestones and schedules for developing and submitting a complete plan. We are requesting comment on this approach and the timing and frequency of updates that the state must provide.

3. Components of an initial state plan submittal and approvability criteria

As noted, if a state is unable to prepare and submit a complete plan by June 30, 2016, the state must make an initial submittal by that date. To be approved, the EPA proposes that the initial plan must address all components of a complete plan.

259 This update would only apply to states that receive a two-year extension for the submission of a complete plan, by June 30, 2018.
including identifying which components are not complete. For incomplete components, an approvable initial submittal must contain a comprehensive roadmap outlining the path to completion, including milestones and dates. We recognize that certain options that states may choose involve more analytic effort to precisely demonstrate sources of reductions than other options. The initial plan, the initial plan must include the following information:

- A description of the plan approach and progress to date in developing a complete plan
- Initial quantification of the level of emission performance that will be achieved through the plan
- A commitment to maintain existing measures that limit or avoid 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.

A description of all steps the state has already taken in furtherance of actions needed to finalize a complete plan.

The EPA is soliciting comment on whether there are other elements that a state must include in its initial submittal to qualify for a date extension.

For states participating in a multi-state program, the initial submittal should include executed agreements among the participating states and a road map for both design of the multi-state program and its implementation at the state level. The RGGI provides an example of such an approach. The RGGI participating states signed a Memorandum of Understanding (MOU) in December 20, 2005, in which the states “express[ed] their
mutual understandings and commitments”.<sup>260</sup> The MOU included a detailed outline of the multi-state emission budget trading program, which served as a guide for drafting a model rule. The MOU also included commitments by the participating states to draft and finalize the model rule by specified dates, and a commitment to seek to establish in statute and/or legislation a program materially consistent with the model rule in each state by a specified date.<sup>261</sup> The MOU also included a commitment to launch the program by January 1, 2009 in all states and specified a process for establishing a non-profit organization to assist the states in administering the regional aspects of the program. In addition, prior to execution of the MOU, the RGGI states committed, through letters from the Governors of participating states, to engage in the development of a market-based program to reduce CO₂ emissions from power plants. This was followed by publication of an action plan for tasks leading up

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<sup>260</sup> Regional Greenhouse Gas Initiative Memorandum of Understanding, available at http://rggi.org/design/history/mou. Two states subsequently signed the original MOU in early 2007 and a third joined the program later that year through an amendment of the MOU; one of the original states withdrew from the MOU in late 2011.

<sup>261</sup> The model rule specified elements that needed to be consistent across states for the program to function, as well as areas where state rules could differ (e.g., the method used for allocating CO₂ allowances). For more information, see Regional Greenhouse Gas Initiative Model Rule, available at http://rggi.org/docs/ProgramReview_FinalProgramReviewMaterials/Model_Rule_FINAL.pdf.
4. Process for EPA review of state plans

Following the June 30, 2016, deadline for state plan submittals, the EPA will review plan submittals for approvability. For a state that submits an initial state plan by June 30, 2016, and requests an extension of the deadline for the submission of a complete state plan, the EPA will determine if the initial plan submittal meets the minimum requirements for an initial state plan. If it meets the minimum requirements for an initial state plan, as specified in the emission guidelines, then the EPA will notify the state by letter, within 60 days, that it has received the plan and that the initial state plan meets the minimum requirements. The letter will also specify whether the complete plan must be submitted to the EPA by no later than June 30, 2017, or June 30, 2018.

After receipt of a complete plan submittal, the EPA will review the plan and, within six months, approve or disapprove the plan through a notice-and-comment rulemaking process similar to that used for approving state implementation plan submittals under section 110 of the Act.

F. State Plan Considerations
The EPA is proposing to give states broad discretion to develop plans that best suit their circumstances and policy objectives. In developing its plan, a state will need to make a number of decisions that will require careful consideration, in order to ensure that its plan both meets a state’s policy objectives and is approvable by the EPA. In this section, we identify several key decision points and factors that states should consider when developing their plans.

The EPA has also prepared a TSD, titled “State Plan Considerations,” that provides further information on these topics. The agency is seeking comment on the contents of this TSD and all aspects of the state plan decision points and factors below.

1. Affected entities other than affected EGUs

A state will need to identify each affected entity responsible for meeting compliance obligations under its plan and the means by which compliance with each plan requirement will be met, as well as demonstrate that it has the legal authority to subject such entities to the federally enforceable requirements specified in its state plan. We are proposing that affected entities in an approvable state plan may include: an owner or operator of an affected EGU, other affected entities with responsibilities assigned by a state (e.g., an entity that
is regulated by the state, such as an electric distribution utility, or a private or public third-party entity), and the state agency, authority or entity. 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 for affected entities other than EGUS, and if so, which such entities, and the justification for the limitations on the entities. The State Plan Considerations TSD provides illustrative examples of possible entities and legal mechanisms.

2. Treatment of existing state programs
   a. Framing considerations
Many state officials and stakeholders have said that the EPA should avoid structuring the CAA section 111(d) emission guidelines in a way that would disadvantage states that already have adopted programs that reduce CO₂ emissions. The EPA agrees with that policy principle.

There is much less agreement among states and stakeholders on the specifics of how existing state programs should be treated in a demonstration that a proposed state plan will achieve the required level of emission performance.

The EPA, starting from recent historical data, has identified the affected EGU emission performance improvements and resulting average emission performance levels for affected EGUs that are achievable, considering cost, in each state over the 2020-2029 period, with achievement of the final CO₂ emission performance level by 2030.

As explained in Section VII above, the EPA’s proposed state-specific goals reflect actions that many states have already taken to reduce or avoid EGU 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

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assess certain building blocks that are applied in calculating a state emission performance goal.262

The agency recognizes that states that have already shifted toward lower carbon-intensity generation or ramped up demand-side EE programs are better positioned to meet state-specific goals. For example, states where significant shifts in generation to NGCC units have already occurred would be closer to the generation mix reflected in the state goals than states where NGCC capacity is not yet being operated to the same degree. Likewise, states with relatively well-established demand-side EE programs would be able to build on those programs more quickly than states with less established programs, and would be closer to, or in some cases already achieving, the level of demand-side energy efficiency reflected in the state goals.

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,263 may qualify for use in showing

262 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.
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 performance period as a result of actions taken after the date of this 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

263 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.

264 We are also proposing that this proposed limitation would not apply to existing renewable energy requirements, programs and measures because existing renewable energy generation prior to the date of proposal of the emission guidelines was factored into the state-specific CO₂ goals as part of building block 3.
that the EPA used to propose state emission 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 would ensure that actions taken after proposal of the emission guidelines and prior to 2020 as a result of requirements in a state plan, could be recognized as contributing toward meeting a state’s required emission performance level for affected EGUs.

In general, the agency has identified two broad options for treatment of existing state programs and measures. As noted above, the EPA proposes that emission reductions that existing state requirements, programs, or measures achieve during the plan performance period due to actions taken after a specified date may be recognized in determining emission performance under a state plan. While proposing that the “specified date” would be the date of proposal of these emission guidelines, the EPA also requests comment on the following alternatives: the start date of the plan performance period, the date of promulgation of the emission guidelines, the end date of the base period for the EPA’s BSER-based goals analysis (e.g., beginning of 2013 for blocks 1-3 and beginning of 2017 for block 4, end-use energy efficiency), the end of 2005, or another date.
For this option, we are seeking comment on the point in time after which such actions should be able to qualify for use during a plan performance period, considering the method used to set state goals. Whether this option is consistent in practice with the EPA’s application of BSER may depend on the date or dates that are applied for qualifying actions under existing state programs, requirements, and measures. For example, implementation of measures subsequent to the proposal or promulgation of the emission guidelines may be consistent with a forward-looking goal setting approach, as these actions may be necessary to meet a required level of emission performance during the plan performance period or will put a state in a better position to meet the required level of performance. An example is the EPA’s treatment of end-use energy efficiency potential in state goal setting, where the energy savings achievable during the plan performance period are premised in part on a ramping up of end-use energy efficiency programs and cumulative energy savings prior to the beginning of the plan performance period. Earlier dates may also be consistent with a forward-looking goal setting approach, if the goal-setting approach is premised in part on actions that could be taken prior to the 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. This option would recognize emission reductions that existing state requirements, programs, or measures achieved starting from a specified date prior to the plan performance period, as well as emission reductions achieved during a plan performance period. The specified date could be, for example: the date of promulgation of the emission guidelines; the date of proposal of the emission guidelines; the end date of the base period for the EPA’s BSER-based goals analysis (e.g., 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 performance 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 the state plan performance period, could be applied toward meeting the required level of emission performance in a state plan.

c. Application of options under rate-based and mass-based plan approaches

Under a rate-based approach, the options described above would address the eligibility date for qualifying demand-side EE measures that, through MWh savings, avoid CO₂ emissions from affected EGUs. Measures installed after the eligibility date could generate MWh savings during a plan performance 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 demand-side EE measures installed in 2015 or later to meet an existing, on-the-books energy efficiency resource standard would be a qualifying measure. However, only MWh savings 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, 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 the incremental requirements of an end-use energy efficiency resource standard requirement in a reference case projection, beginning at a specified date. These considerations are addressed in more detail in Section VIII.F.7. below and in the Projecting CO₂ Emission Performance in State Plans TSD.

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

We are proposing that RE and demand-side EE measures may be incorporated into a rate-based approach through an adjustment or
tradable credit system applied to an EGU’s reported CO2 emission rate. Under such a process, measures that avoid CO2 emissions from affected EGUs, such as quantified and verified end-use energy savings and renewable energy generation, could be credited toward a demonstrated CO2 emission rate for EGU compliance purposes or used by the state to administratively adjust the average CO2 emission rate of affected EGUs when demonstrating achievement of the required emission rate performance level in a state plan.

Under this approach, affected EGUs could comply with a CO2 emission rate limit in part through the use of credits for actions that avoid CO2 emissions from affected EGUs. If a state is implementing a portfolio approach, then the state could administratively adjust the average CO2 emission rate of affected EGUs through a similar process, provided that the CO2-avoiding measures are enforceable elements of the state plan.

We are seeking comment on different approaches for providing such crediting or administrative adjustment of EGU CO2

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265 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.

266 This could include an individual affected EGU or group of affected EGUs if a rate-based averaging or trading approach is used.
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 CO₂ emissions. The approach chosen could have significant implications for the amount of adjustment or credit provided for RE and demand-side EE measures. If adjustment or credits represent avoided MWh, they would be added to the denominator when determining an adjusted lb CO₂/MWh emission rate. If adjustment or credits represent avoided CO₂ emissions, they would be subtracted from the numerator when determining an adjusted lb CO₂/MWh emission rate.

A MWh crediting or adjustment approach implicitly assumes that the avoided CO₂ 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 CO₂ emissions from that individual EGU or group of EGUs. In practice, the average or marginal CO₂ emission rate in the power pool or identified region

267 As a result, the assumed avoided CO₂ emissions from an individual MWh of energy savings or MWh of generation from 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.
- 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 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 electricity savings.

The EPA is proposing that a state plan that includes enforceable RE and demand-side EE measures must include an evaluation, measurement, and verification (EM&V) plan that explains how the effect of these measures will be determined in the course of plan implementation. An EM&V plan will specify the analytic methods, assumptions, and data sources that the state will employ during the state plan performance periods to determine the energy savings and energy generation related to RE and demand-side EE measures. An EM&V plan would be subject to EPA approval as part of a state plan. As discussed below, the EPA intends to develop guidance on acceptable EM&V methods that could be incorporated in an approvable EM&V plan included as part of an approvable state plan.
Utilities and states have conducted ongoing EM&V of demand-side energy efficiency and renewable energy measures and programs for several decades. Current practice with EM&V for demand-side energy efficiency and renewable energy programs in the U.S. is primarily defined by state public utility commission (PUC) requirements for customer-funded energy efficiency programs, as well as related compliance and reporting requirements for energy efficiency resource standards (EERS) and renewable energy portfolio standards (RPS).

The level of PUC oversight of demand-side energy efficiency programs varies from state to state, but this oversight process has generated the majority of the industry guidance and protocols for documenting energy savings from EE programs. Typically, impact evaluation reports are responsive to requirements established by PUCs and submitted (usually annually) for PUC review, approval, and use in resource planning and performance assessment. These PUC requirements generally rely upon a well-defined set of industry-standard practices and procedures. In states with the most experience implementing and overseeing EE programs, this typically includes: use of one or more of industry-standard EM&V protocols or guidelines; use of

**Deleted:** These evaluations, which include quantification, monitoring, and verification of results,

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“deemed savings values,”268 where appropriate, for well-understood energy efficiency measures; consideration of local factors, such as climate, building type, and occupancy; involvement of stakeholders and solicitation of expert advice regarding EM&V processes and resulting energy savings impacts; conduct of EM&V activities (e.g., direct equipment measurements, application of deemed savings, and reporting of impacts) on a regular basis; and provision of interim and annual reporting of achieved energy savings.

Despite this well-defined and generally accepted set of industry practices, many states with energy efficiency programs use different input values and assumptions in applying these practices (e.g., net versus gross savings269, run-time of equipment, measure lifetime). This can result in significant differences in claimed energy savings values for similar energy efficiency measures between states and utilities, even when the same measure type is installed under otherwise identical

268 Deemed savings are measure-specific stipulated values based on historical and verified data. Unlike other EM&V approaches, deemed savings approaches involve limited or no measurement activities, and are therefore a common and relatively low-cost strategy for documenting energy savings.

269 Gross savings are the change in energy use (MWh) and demand (MW) that results directly from program-related actions taken by program participants, regardless of why they participated in a program. Net savings refer to the change in energy use and demand that is directly attributable to a particular energy efficiency program.
circumstances. In response to a growing awareness of this lack of cross-state comparability, policy makers, regulatory agencies, and other stakeholders are increasingly advocating for the use of common evaluation approaches across jurisdictions. A number of states and utilities in different regions of the country are already working to develop such common approaches.

For renewable energy measures and programs, EM&V employed by states and utilities commonly relies upon a set of standard practices and procedures, such as the use of revenue-quality meters for quantifying RE generation. As a result, existing state and utility requirements and processes for quantification, monitoring, and verification of RE programs and measures generally provide a solid foundation for minimum requirements or guidance established by EPA for state plans.

For both RE and demand-side EE measures included in state plans, additional information and reporting may be necessary to accurately quantify the avoided CO2 emissions associated with these measures, such as information on the location and the hourly, daily, or seasonal basis of renewable energy generation or energy savings.

Current state and utility EM&V approaches for RE and demand-side EE programs and mandates are discussed in more detail in the State Plan Considerations TSD. We are seeking
comment on the suitability of these approaches in the context of
an approvable state plan, and on whether harmonization of state
approaches, or supplemental actions and procedures, should be
required in an approvable state plan. In particular, we intend
to establish guidance for acceptable quantification,
monitoring, and verification of RE and demand-side EE measures
for an approvable EM&V plan, and are seeking comment on critical
features of such guidance, including scope, applicability, and
minimum requirements.270 We are also seeking comment on the
appropriate basis for and technical resources used to establish
such guidance, including consideration of existing state and
utility protocols, as well as existing international, national,
and regional consensus standards or protocols.271 The EPA’s goal
in developing such guidance is to assure that it is consistent
with industry-standard EM&V approaches for both RE and demand-
side EE measures and programs, leverages the EM&V resources and
infrastructure already in place in many states, and strikes a
reasonable balance between EM&V costs, rigor, and the value of
resulting information, while considering the specific use of

270 Section 4 of the State Plan Considerations TSD includes a
detailed description of these EM&V parameters.
271 A list of these protocols is provided in Section 3.1 of the
State Plan Considerations TSD.
such information in assessing avoided CO₂ emissions from affected EGUs.

In developing guidance, the agency does not intend to limit the types of RE and demand-side EE measures and programs that can be included in a state plan, provided that supporting EM&V is rigorous, complete, and consistent with EPA’s guidance. This approach recognizes differences among RE and demand-side EE programs and measures with respect to implementation history and experience, existence of applicable EM&V protocols and methods, and the nature and type of program oversight (e.g., whether or not a program is subject to PUC oversight). The EPA is requesting comment on the merits of this approach, including whether such guidance should identify types of RE and demand-side EE measures and programs for which evaluation of results is relatively straightforward and which are appropriate for inclusion in a state plan. Such approaches might be subject to streamlined review of EM&V protocols included in an approvable plan, provided that such protocols are applied in accordance with industry best practices. For example, many utilities have implemented a similar core set of RE and demand-side EE measures and programs for utility customers. For these types of measures and programs, a substantial base of experience has been established nationally for the evaluation of measure and program
outcomes. Other types of measures and programs, such as those that seek to alter consumer and building occupant behavior 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, and the EPA does not want to discourage their implementation in state plans, but they may require development of appropriate quantification, monitoring, and verification protocols. The EPA and its federal partners intend to discuss the development of appropriate EM&V protocols for such measures with states in the coming years.

As an alternative to the EPA’s proposed approach of allowing a broad range of RE and demand-side EE measures and programs to be included in state plans, provided that supporting EM&V documentation meets applicable minimum requirements, EPA is requesting comment on whether guidance should limit consideration to certain well-established programs, such as those characterized in Section 4.2.1 of the State Plan Considerations TSD.

5. Reporting and recordkeeping for affected entities implementing RE and demand-side EE measures
If a state plan incorporates RE and demand-side EE measures under a rate-based approach or implements a mass-based portfolio approach with such measures, reporting and recordkeeping requirements for an approvable plan would differ from those applicable to an affected EGU. For example, these requirements may include compliance reporting by an electric distribution utility subject to an 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 end-use energy and clean energy technologies that are incorporated into a state plan. In each of these instances, reporting of program compliance or program outcomes is a necessary part of an approvable plan to demonstrate performance under the plan.

Examples of potential reporting obligations for affected entities implementing RE and demand-side EE measures in an
approvable state plan are provided in the State Plan Considerations TSD. We are seeking comment on the examples and suitability of potential approaches described in the TSD and any other appropriate reporting and recordkeeping requirements for affected entities beyond affected EGUs.

6. Treatment of interstate effects

The electricity system and wholesale electricity markets are interstate in nature. EGUs in one state provide electricity to customers in neighboring states. Power companies often own EGUs in more than one state and manage them as a system. EGUs are dispatched both within and across state borders.

Similarly, programs and measures in a state plan, such as RE and demand-side EE measures, may affect the performance of the interconnected electricity system beyond a state border. In addition, many state programs allow for actions in neighboring states to meet the in-state requirement or explicitly address 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 allow state to take into account the CO2 emission reductions resulting from these programs, while minimizing 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 under the plan. In addition, a state plan that is using a mass-based goal in determining the required level of emission performance under the plan will include a translation of the rate-based emission goal in the emission guidelines to a mass-based goal.
This translation will involve a projection of 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 must 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 CAA section 111(d) will depend in large part on ensuring credible and consistent emission performance projections in state plans. Therefore, the use of appropriate methods, tools, and assumptions for such projections is critical.

Considerations for projecting emission performance under a state plan will differ depending on the type of plan. This includes differences in how inputs to projections are derived; how projections are conducted, including tools, methods, and
assumptions; and, how aspects of a plan are represented in these projections.

In general, 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 emission performance under different types of state plan approaches, are discussed in detail in the Projecting EGU CO₂ Emission Performance in State Plans TSD.

We are seeking comment on the considerations discussed in this TSD, including options presented for how projections might be conducted in an approvable state plan, and how different types of state plan approaches are represented in these

272 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.
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 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.

8. Consideration of measures that the EPA did not include in the BSER determination

States may include measures in their plans beyond those that the EPA included in its determination of the BSER. A wide
range of other measures that could CO₂ emission reductions. These include, for example, transmission improvements, retrofitting EGUs with partial CCS, the use of biomass-derived fuels, use of new NGCC units online, and new hydroelectric power and increments, and they are among the measures that states might consider for inclusion in their plans. The agency solicits comment on whether these measures are appropriate to include in a state plan to achieve CO₂ emission reductions. We also request comment on other measures that would be appropriate. In addition, should the EPA provide specific guidance on these measures?

We request comment, in particular, on the use of biomass-derived fuels, in place of affected EGUs, as a measure to include in a state plan to achieve CO₂ emission reductions. Through President Obama’s Climate Action Plan, the Administration is working to identify new approaches to protect and restore our forests, as well as other critical landscapes including grasslands and wetlands, in the face of a changing climate. Sustainable forestry and agriculture can improve resiliency to climate change, be part of a national strategy to reduce dependence on fossil fuels, and contribute to climate change mitigation by acting as a “sink” for carbon. The plant growth associated with producing many of the biomass-derived
fuels can, to varying degrees for different biomass feedstocks, sequester carbon from the atmosphere. For example, America’s forests currently play a critical role in addressing carbon pollution, removing nearly 12 percent of total U.S. greenhouse gas emissions each year. As a result, broadly speaking, burning biomass-derived fuels for energy recovery can yield climate benefits as compared to burning conventional fossil fuels.

Many states have recognized the importance of forests and other lands for climate resilience and mitigation and have developed a variety of different sustainable forestry policies, renewable energy incentives and standards and greenhouse gas accounting procedures. Because of the positive attributes of certain biomass-derived fuels, the EPA also recognizes that biomass-derived fuels can play an important role in carbon dioxide (CO₂) emission reduction strategies. We anticipate that states will likely consider biomass-derived fuels in energy production as a way to mitigate the CO₂ emissions attributed to the energy sector and include them as part of their plans to meet the emission reduction requirements of this rule and we think it is important to define a clear path for states to do so.

To better understand the impacts of using different types of biomass-derived fuels, the EPA is assessing the use of
biomass feedstocks for energy recovery by stationary sources and
developed a draft accounting framework which EPA’s Science
Advisory Board (SAB) has reviewed. The draft framework concluded
that while biomass and other biogenic feedstocks have the
potential to reduce the overall level of CO₂ emissions resulting
from electricity generation, the contribution of biomass-derived
fuels to atmospheric CO₂ is sensitive to the type of biomass
feedstock used, and the way in which the feedstock is grown,
processed, and ultimately combusted as a fuel for energy
production. The SAB in its review similarly found that there are
circumstances in which biomass is grown, harvested and combusted
in a carbon neutral fashion but commented that additional
considerations are warranted.

The EPA is in the process of revising the draft framework
and considering next steps, taking into account both the
comments provided by the SAB and feedback from
stakeholders. Once finalized, the EPA’s biogenic CO₂ accounting
framework is expected to provide important information regarding
the scientific basis for assessing these biomass-derived fuels
and their net atmospheric contribution of CO₂ related to the
growth, harvest and use of these fuels. This information should
assist both states and the EPA in assessing the impact of the
use of biomass fuels in reaching emission reduction goals in the
energy sector under state plans to comply with the requirements in the emission guidelines.

9. Consideration of a facility’s “remaining useful life” in applying standards of performance

In this section, the EPA discusses the relevance to this rule of the statutory provision that requires EPA regulations implementing CAA 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 CAA section 111(d) including the “remaining useful life” statutory provision, application of the implementing provisions in the framework regulations may not be appropriate in every instance. For the reasons discussed below, the EPA is proposing that, in this case, the flexibility provided in the state plan development process adequately allows for consideration of the remaining useful life of the affected facilities and other source-specific factors and, therefore, that separate application of the remaining useful life provision

273 The agency is not reopening or considering changes to the existing framework regulations.
by states in the course of developing and implementing their CAA section 111(d) plans is unnecessary. The agency is requesting comment on its analysis below of the implications of the EPA’s existing regulations interpreting “useful life” and “other factors” for purposes of this rulemaking. 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.

This section addresses the legal background concerning facility-specific considerations and the implications for implementation of these emission guidelines, including state emissions performance goals.

a. Legal background

As reflected in the framework regulations, the EPA believes that Congress included the remaining useful life provision in CAA 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, 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 resulting from 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 CAA section 111(d). The opening clause, however, which provides that this provision is applicable “unless otherwise specified in the applicable subpart” makes clear that this structure may not be appropriate in each case and that the EPA has discretion to alter the extent to which states may authorize relaxations to standards of performance that would otherwise apply to a particular source or source category, if appropriate under the circumstances of the specific source category and proposed guidelines.

b. Implications for implementation of 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. Such guidelines are much more like a CAA section 111(b) standard in their form. For example, the EPA emission guidelines for sulfuric acid plants, phosphate fertilizer plants, primary aluminum plants, and Kraft pulp plants specify emission limits for sources. 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 state plans to limit CO₂ from 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 CAA 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

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276 [cites]
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 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.

Therefore, to the extent that a performance standard that a state may wish to adopt for affected EGUs raises facility-specific issues, the state would be authorized to make adjustments to a particular facility’s requirements on facility-specific grounds, so long as any such adjustments are reflected (along with any necessary compensating emission reductions), as part of the state’s CAA section 111(d) plan submission. The agency requests comment on its interpretation.

c. Relationship to state emission performance goals and timing of achievement

The EPA also believes that 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 CAA section 111(d) plan that achieves that goal by the applicable deadline.

Under the proposed guideline, states would have the flexibility to adopt a state plan that relies on emission-reducing requirements that do not require affected EGUs with a short remaining useful life to make major capital expenditures or incur unreasonable costs. Indeed, the EPA’s proposal would provide states with broad flexibility regarding ways to improve emission performance through utilizing the emissions reduction methods represented by the four “building blocks.” 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 EGUs, the assumed 6 percent heat rate improvement in the EPA’s proposed

277 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.
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 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; a fleet-wide average cost for heat rate improvements at coal-fired generating units is $100/kW, compared with a typical SO2 scrubber cost of $500/kW (costs vary with unit size). In addition, the proposed guideline allows states to regulate affected EGUs through flexible regulatory approaches that do not require affected EGUs to incur large

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 the EPA’s BSER analysis, as long as they provide additional compensating emission reductions with respect to the other three building blocks.

Heat rate improvement methods and related capital costs are discussed in the GHG Abatement Measures TSD; SO2 scrubber capital costs are from the documentation for EPA’s IPM Base Case v5.13, Chapter 5, Table 5-3, available at http://www.epa.gov/powerssectormodeling/BaseCasev513.html
capital costs (e.g., *averaging and trading programs*). Under EPA’s proposed approach -- establishing state goals and providing states with flexibility in plan design – states have flexibility to avoid requirements that would result in stranded assets.

Remaining useful life and other factors, because of their facility-specific nature, are potentially relevant in determining requirements that are directly applicable to affected EGUs. For all of the reasons above, the agency believes that the issue of remaining useful life will arise infrequently in the development of state plans to limit 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 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, the EPA operated the emissions trading program for New Hampshire sources, from allocating allowances to compliance determination.

Additionally, as noted elsewhere in this preamble, more than 25 states have mandatory renewable portfolio standards and other states have voluntary renewable programs and goals. There is considerable diversity among the states in the scope and coverage of these standards, in particular in how renewable resources are defined. At the federal level, the EPA has considered the greenhouse gas implications related to biomass use at stationary sources through several actions, including a call for information from stakeholders and the development and
review of the “Accounting Framework for Biogenic 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 CAA section 111(d) plans.

H. Resources for States to Consider in Developing Their Plans

As part of the stakeholder outreach process, the EPA asked states what the agency could do to facilitate state plan development and implementation. Some states indicated that they wanted the EPA to create resources to assist with state plan development, especially resources related to accounting for end-use energy efficiency and renewable energy (EE/RE) in state plans. They requested clear methodologies for 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,”[^280] as well as the State Energy Efficiency Action Network’s “Energy

Efficiency Program Impact Evaluation Guide.\textsuperscript{281} 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 CO\textsubscript{2} emissions from the electric utility sector.

For the final rulemaking, the EPA plans to organize resources around the following two categories: state plan guidance and state plan decision support. The state plan guidance section will serve as a central repository for the final emission guidelines, regulatory impact analysis, technical support documents, and other supporting materials. The state plan decision support section will include information to help states evaluate different approaches and measures they might consider as they initiate plan development. This section will include, for example, a summary of existing state climate and

\textsuperscript{281}
http://www1.eere.energy.gov/seeaction/pdfs/emv_ee_program_impact_guide.pdf
EE/RE policies and programs, National Action Plan for Energy Efficiency (Action Plan), information on electric utility actions that reduce CO2, 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.

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

282 Appendix, State Plan Considerations TSD
283 http://www.epa.gov/cleanenergy/energy-programs/sucha/resources.html
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 CO2e 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 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 section 111 of the CAA would make GHGs “regulated air
pollutants” for the first time under the operating permit
regulations of 40 CFR parts 70 and 71. This would result in GHGs
becoming “fee pollutants” in certain state part 70 permit
programs and in the EPA’s part 71 permit program, thus requiring
the collection of fees for GHG emissions in these
programs. Where title V fees would be required for GHGs, they
would typically be charged at the same rate ($ per ton of
pollutant) as all other fee pollutants. This would likely result
in excessive and unnecessary fees being charged to subject
sources. To avoid this situation, we proposed to exempt GHGs
from the fee rates in effect for other fee pollutants, while
proposing an alternative fee that would be much lower than the fee charged to other fee pollutants, yet sufficient to cover the costs of addressing GHGs in operating permits.

This title V fee issue is a one-time occurrence resulting from the promulgation of the first CAA section 111 standard to regulate GHGs (the EGU NSPS for new sources) and is not an issue for any other subsequent section 111 regulations, so there is no need to address any title V fee issues in this proposal. Thus, we are not re-visiting these title V fee issues in this proposal, and we are not proposing any additional revisions to any title V regulations as part of this action.

The title V regulations require each permit to include emission limitations and standards, including operational requirements and limitations that assure compliance with all applicable requirements. Requirements resulting from this rule that are imposed on affected EGUs or any other potentially affected entities that have title V operating permits are applicable requirements under the title V regulations and would need to be incorporated into the source’s title V permit in accordance with the schedule established in the title V regulations. For example, if the permit has a remaining life of 3 years or more, a permit reopening to incorporate the newly applicable requirement shall be completed no later than 18
months after promulgation of the applicable requirement. If the permit has a remaining life of less than 3 years, the newly applicable requirement must be incorporated at permit renewal.

C. **Interactions with Other EPA Rules**

Existing fossil fuel-fired EGUs, such as those covered in this proposal, are or will be potentially impacted by several other recently finalized or proposed EPA rules. On February 16, 2012, the EPA issued the mercury and air toxics standards (MATS) rule (77 FR 9304) to reduce emissions of toxic air pollutants from new and existing coal- and oil-fired EGUs. The MATS rule will reduce emissions of heavy metals, including mercury (Hg), arsenic (As), chromium (Cr), and nickel (Ni); and acid gases, including hydrochloric acid (HCl) and hydrofluoric acid (HF). These toxic air pollutants, also known as hazardous air pollutants or air toxics, are known or suspected of causing damage to the nervous system, cancer, and other serious health effects. The MATS rule will also reduce SO2 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.

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284 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.
The EPA is closely monitoring MATS compliance and finds that the industry is making substantial progress. Plant owners are moving proactively to install controls that will achieve the MATS performance standards. Certain units, especially those that operate infrequently, may be considered not worth investing in given today's electricity market, and those are closing.

Existing sources subject to the MATS rule are given until April 16, 2015 to comply with the rule's requirements. The final MATS provided a foundation on which states and other permitting authorities could rely in granting an additional, 4th year for compliance provided for by the Act. States report that these 4th year extensions are being granted. In addition, the EPA issued an enforcement policy that provides a clear pathway for reliability-critical units to receive an administrative order that includes a compliance schedule of up to an additional year, if it is needed to ensure electricity reliability. On [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.\textsuperscript{285} 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 will 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, and as a result, is not projected to impose a substantial cost burden on affected facilities. With respect to entrainment, the rule calls upon the permitting authority to 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.

\textsuperscript{285} 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.
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 fossilfuel-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.\footnote{Beneficial use involves the reuse of CCRs in a product to replace virgin raw materials that would otherwise be obtained}
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 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.\(^{287}\) The EPA is under a court-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).

ordered deadline to complete the CCR rulemaking by December 19, 2014.

The EPA recognizes the importance of assuring that each of the rules described above can achieve its intended environmental objectives in a commonsense, cost-effective manner consistent with underlying statutory requirements and while assuring a reliable power system. Executive Order (EO) 13563, “Improving Regulation and Regulatory Review,” issued on January 18, 2011, states that “[i]n developing regulatory actions and identifying appropriate approaches, each agency shall attempt to promote... coordination, simplification, and harmonization. Each agency shall also seek to identify, as appropriate, means to achieve regulatory goals that are designed to promote innovation.”

Within the EPA, we are paying careful attention to the interrelatedness and potential impacts on the industry, reliability and cost that these various rulemakings can have.

As discussed in Sections VII and VIII of this preamble, the EPA is proposing to give states broad flexibility in developing approvable plans under CAA section 111(d), including the ability to adopt rate-based or mass-based emission performance goals, and to rely on a wide variety of 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.288

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

288 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.
coordinate planning and investment decisions with respect to those rules) and, where possible, implement integrated compliance strategies. For example, in the proposed SE ELG rule, the EPA describes its current thinking on how it might effectively harmonize the potential requirements of that rule with the requirements of the final CCR rule, to the extent that both rules may regulate or affect the disposal of coal combustion wastes to and from surface impoundments at power plants.\textsuperscript{289} 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.\textsuperscript{290}

\textsuperscript{289} See: Federal Register Vol. 78, No. 110; June 7, 2013. Page 34441.

\textsuperscript{290} [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
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.

timeline for implementation that allows for coordinated planning and protects electricity reliability for consumers.
The SO$_2$ NAAQS was revised in June 2010 to protect public health from the short-term effects of SO$_2$ exposure. In July 2013, the EPA designated 29 areas in 16 states as nonattainment for the SO$_2$ NAAQS. The EPA based these nonattainment designations on the most recent set of certified air quality monitoring data as well as an assessment of nearby emission sources and weather patterns that contribute to the monitored levels. The EPA intends to address the designations for all other areas in separate actions in the future. The EPA has proposed the data requirements rule for the 1-hour SO$_2$ NAAQS to require states to characterize air quality more extensively using ambient monitoring or air quality modeling approaches.

The EPA requires SIP updates every 10 years for regional haze, as required by the EPA’s Regional Haze Rule which was promulgated in 1999. The next 10-year SIP revision for regional haze, covering the time period through 2028, is due from each state by July 2018. Each SIP must provide for reasonable progress towards visibility improvement in protected scenic areas.

The EPA has developed a comprehensive implementation strategy for these future actions that focuses resources on identifying and addressing unhealthy levels of SO$_2$ in areas where people are most likely to be exposed to violations of the standard. The strategy is available at: http://www.epa.gov/airquality/sulfurdioxide/implement.html.
The development of these SIPs may, where applicable, have significant implications for existing fossil fuel-fired EGUs, as well as for the states that are responsible for developing them. The timeframes for submittal of SIPs for the various programs and the timeframes we are proposing for submittal of the CAA section 111(d) state plans will allow considerable time for coordination by states in the development of their respective plans. The EPA is willing to work with states to assist them in coordinating their efforts across these planning processes. The EPA believes that CAA section 111(d) efforts and actions will tend to contribute to overall air quality improvements and thus should be complementary to criteria pollutant and regional haze SIP efforts.

In light of the broad flexibilities we are proposing in 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 guidelines. CO₂ emissions are projected to be reduced, relative to 2005 emissions, by 26 percent to 27 percent in 2020 and about 30 percent in 2030 under Option 1. Option 2 reflects reductions of about 23 percent in 2020 and 22 percent to 23 percent in 2030. The guidelines are projected to result in substantial co-benefits through reductions of SO₂, PM₂.₅ and NOx that will have direct public health benefits by lowering ambient levels of these pollutants and ozone. Tables 7 and 8 show expected CO₂ and other air pollutant emission reductions in the base case, with the proposed Option 1 and regulatory alternative Option 2, respectively, for 2020, 2025, and 2030.

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 7 – Summary of CO₂ and Other Air Pollutant Emission Reductions with Option 1

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### Table 8: Summary of CO₂ and Air Pollutant Emission Reductions with Option 2

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<td>Emissions Reductions</td>
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<td>-317</td>
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<tr>
<td>2030 State Compliance Approach</td>
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<tr>
<td>Base Case</td>
<td>2,256</td>
<td>1,530</td>
<td>1,537</td>
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<tr>
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<td>1,209</td>
<td>1,264</td>
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<tr>
<td>Emissions Reductions</td>
<td>-373</td>
<td>-321</td>
<td>-274</td>
<td></td>
</tr>
</tbody>
</table>

The reductions in these tables do not account for reductions in hazardous air pollutants (HAPs) that may occur as a result of this rule. For instance, the fine particulate reductions presented above only partly reflect reductions in many heavy metal particulates.

B. Comparison of Building Block Approaches

Though the EPA has determined that the 4-building block approach is BSER, we did analyze the impacts of both a combination of building blocks 1 and 2 and the combination of all four building blocks. The analysis indicates that the combined strategies of heat rate improvements (building block 1) and re-dispatch (building block 2) would result in overall CO₂ emission reductions of approximately 22 percent in 2020 (compared to 2005 emissions and assuming state-level compliance). This compares to expected CO₂ emission reductions of approximately 27 percent for the four-block BSER approach discussed below. The EPA analysis also estimates 24 – 32 GW of additional coal-fired EGU retirements in 2020 (compared to 46 – 49 GW for the four-block approach) and an additional 3 – 5 GW of oil/gas steam EGUs (compared to 16 GW for the four-block...
approach). For both the two-block and the four-block approach, a
decrease in coal production and price is predicted in 2020. The
decrease in production is predicted at 20 – 23 percent for the
two-block approach, compared to a decrease of 25 – 27 percent
for the four-block approach. A 12 percent decrease in coal
prices is predicted for the two-block approach; while the four-
block approach results in a 16 to 18 percent decrease. Under
both approaches, the shifting in generation from higher-emitting
steam EGUs to lower-emitting NGCC units results in an increase
in natural gas production and price. The two-block approach
results in a production increase of 19 – 22 percent and a price
increase of 10 – 11 percent. The four-block approach results in
a production increase of 12 – 14 percent and a price increase of
9 – 12 percent. Both the two-block and the four-block approaches
result in construction of additional NGCC capacity by 2020, with
11 – 18 GW of new NGCC for the two-block approach and 20 – 22 GW
of new NGCC capacity for the four-block approach. However, while
the two-block approach results in 5 – 17 GW of new NGCC capacity
in 2030, the four-block approach results in 32 – 35 GW less NGCC
capacity in 2030 (due to increased use of renewable energy
sources and decreased demand from implementation of demand side
energy efficiency measures). Also, significantly, the two-block
approach results in less than 500 MW of new renewable energy
capacity; while the four-block option results in approximately 12 GW of new renewable generating capacity.

The EPA projects that the annual incremental compliance cost for the building block 1 and 2 approach is estimated to be $3.2 to $4.4 billion in 2020 and $6.8 to $9.8 billion (2011$) in 2030, excluding the costs associated with monitoring, reporting, and recordkeeping (MRR).

The total combined climate benefits and health co-benefits are estimated to be $21 to $40 billion in 2020 and $32 to $63 billion in 2030 (2011$ at a 3-percent discount rate [model average]). The net benefits are estimated to be $18 to $36 billion in 2020 and $25 to $53 billion in 2030 (2011$ at a 3-percent discount rate [model average]). For the purposes of this summary, we list the climate benefits associated with the marginal value the model average at 3% discount rate, however we emphasize the importance and value of considering the full range of SCC values.

C. Endangered Species Act

Consistent with the requirements of section 7(a)(2) of the Endangered Species Act (ESA), the EPA has also considered the effects of this proposed rule and has reviewed applicable ESA regulations, case law, and guidance to determine what, if any, impact there may be to listed endangered or threatened species.
or designated critical habitat. Section 7(a)(2) of the ESA requires federal agencies, in consultation with the U.S. Fish and Wildlife Service (FWS) and/or the National Marine Fisheries Service, to ensure that actions they authorize, fund, or carry out are not likely to jeopardize the continued existence of federally listed endangered or threatened species or result in the destruction or adverse modification of designated critical habitat of such species. 16 U.S.C. § 1536(a)(2). Under relevant implementing regulations, section 7(a)(2) applies only to actions where there is discretionary federal involvement or control. 50 CFR § 402.03. Further, under the regulations consultation is required only for actions that “may affect” listed species or designated critical habitat. 50 CFR § 402.14. Consultation is not required where the action has no effect on such species or habitat. Under this standard, it is the federal agency taking the action that evaluates the action and determines whether consultation is required. See 51 FR 19926, 19949 (June 3, 1986). Effects of an action include both the direct and indirect effects that will be added to the environmental baseline. 50 CFR § 402.02. Indirect effects are those that are caused by the action, later in time, and are reasonably certain to occur. Id. To trigger a consultation requirement, there must thus be a causal connection between the
federal action, the effect in question, and the listed species, and the effect must be reasonably certain to occur.

The EPA has considered the effects of this proposed rule and has reviewed applicable ESA regulations, case law, and guidance to determine what, if any, impact there may be to listed species or designated critical habitat for purposes of section 7(a)(2) consultation. The EPA notes that the projected environmental effects of this proposal are positive: reductions in overall GHG emissions, and reductions in PM and ozone-precursor emissions (SOx and NOx). With respect to the projected GHG emission reductions, EPA does not believe that such reductions trigger ESA consultation requirements under section 7(a)(2). In reaching this conclusion, the EPA is mindful of significant legal and technical analysis undertaken by FWS and the U.S. Department of the Interior in the context of listing the polar bear as a threatened species under the ESA. In that context, FWS and DOI expressed the view that the best scientific data available are insufficient to draw a causal connection between GHG emissions and effects on the species in its habitat.293 The DOI Solicitor concluded that where the effect at

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293 See, e.g., 73 FR 28212, 28300 (May 15, 2008); Memorandum from David Longly Bernhardt, Solicitor, U.S. Department of the Interior re: "Guidance on the Applicability of the Endangered
issue is climate change, proposed actions involving GHG
emissions cannot pass the “may affect” test of the section 7
regulations and thus are not subject to ESA consultation. The
EPA has also previously considered issues relating to GHG
emissions in connection with the requirements of ESA section
7(a)(2). Although the GHG emission reductions projected for this
proposal are large (the highest estimate is reductions of 555
MMT of CO₂ in 2030 – see Table 7 above), the EPA evaluated larger
reductions in assessing this same issue in the context of the
light duty vehicle GHG emission standards for model years 2012-
2016 and 2017-2025. There the agency projected emission
reductions roughly double and four times those projected here
over the lifetimes of the model years in question and, based
on air quality modeling of potential environmental effects,
concluded that “EPA knows of no modeling tool which can link
these small, time-attenuated changes in global metrics to
particular effects on listed species in particular areas.
Extrapolating from global metric to local effect with such small
numbers, and accounting for further links in a causative chain,
remain beyond current modeling capabilities.” EPA, Light Duty

Species Act’s Consultation Requirements to Proposed Actions

See 75 FR at 25438 Table I.C 2-4 (May 7, 2010); 77 FR at
62894 Table III-68 (Oct. 15, 2012).
Vehicle Greenhouse Gas Standards and Corporate Average Fuel Economy Standards, Response to Comment Document for Joint Rulemaking at 4-102 (Docket EPA-OAR-HQ-2009-4782. The EPA reached this conclusion after evaluating issues relating to potential improvements relevant to both temperature and oceanographic pH outputs. The EPA’s ultimate finding was that “any potential for a specific impact on listed species in their habitats associated with these very small changes in average global temperature and ocean pH is too remote to trigger the threshold for ESA section 7 (a)(2).” Id. The EPA believes that the same conclusions apply to the present proposal, given that the projected CO2 emission reductions are less than those projected for either of the light duty vehicle rules. See, e.g., Ground Zero Center for Non-Violent Action v. U.S. Dept. of Navy, 383 F. 3d 1082, 1091-92 (9th Cir. 2004) (where the likelihood of jeopardy to a species from a federal action is extremely remote, ESA does not require consultation).

With regard to non-GHG air emissions, the EPA is also projecting substantial reductions of SOx and NOx as a collateral consequence of today’s proposal. Preamble Table 7. However, CAA section 111(d)(1) standards cannot directly control emissions of criteria pollutants. Consequently, section 111(d) provides no discretion to adjust the standard based on potential
impacts to endangered species of reduced criteria pollutant emissions. Section 7(a)(2) consultation thus is not required with respect to the projected reductions of criteria pollutant emissions. See 50 CFR § 402.03; see also, National Lime Ass’n v. EPA, 233 F. 3d 625, 638-39 (D.C. Cir. 2000) (although CAA section 112(b)(2) prohibits the EPA from listing criteria pollutants as hazardous air pollutants, the EPA may use PM as a surrogate for metal hazardous air pollutants and reductions in PM do not constitute impermissible regulation of a criteria pollutant).

Moreover, there are substantial questions as to whether any potential for relevant effects results from any element of the proposed rule or would result instead from the separate actions of States establishing standards of performance for existing sources and implementing and enforcing those standards. Cf. American Trucking Assn’s v. EPA, 175 F. 3d 1027, 1043-45 (D.C. Cir. 1999), rev’d on different grounds sub nom., Whitman v. American Trucking Assn’s, 531 U.S. 457 (2000) (National Ambient Air Quality Standards have no economic impact, for purposes of Regulatory Flexibility Act, because impacts result from the actions of States through their development, implementation and enforcement of state implementation plans). Thus, for example, although questions may exist whether actions such as increased
utilization of solar or wind power could have effects on listed species, the EPA believes that such effects (if any) would result from decisions and actions by states in developing, implementing and enforcing their plans. The precise steps States choose to take in that regard cannot be determined or ordered by this federal action, and they are not sufficiently certain to be attributable to this proposed rule for ESA purposes. Consequently, for this additional reason, the EPA does not believe that this proposed rule (if enacted) would have effects on listed species that would trigger the section 7 (a)(2) consultation requirement.

D. What are the energy impacts?

The proposed guidelines have important energy market implications. Under Option 1, average nationwide retail electricity prices are projected to increase by roughly 6 to 7 percent in 2020, and by roughly 3 percent in 2030 (contiguous U.S.). Average monthly electricity bills are anticipated to increase by roughly 3 percent in 2020, but decline by approximately 9 percent by 2030. The decreased projection in these two metrics is a result of the increasing penetration of demand-side programs that more than offset increased prices to end users by their expected savings from reduced electricity use.
The average delivered coal price to the power sector is projected to decrease by 16 to 17 percent in 2020 and roughly 18 percent in 2030, relative to the base case for Option 1. The EPA also projects that electric power sector-delivered natural gas prices will increase by 9 to 12 percent in 2020, with negligible changes by 2030. Natural gas use for electricity generation will increase by as much as 1.2 trillion cubic feet (BCF) in 2020 relative to the base case, declining over time.

These figures reflect EPA’s illustrative modeling that presumes policies that lead to dispatch changes in 2020 and growing use of energy efficiency and renewable electricity generation out to 2029. If states make different policy choices, impacts could be different. For instance, if states implement renewable and/or energy efficiency policies on a more aggressive time-frame, impacts on natural gas and electricity prices would likely be less. Implementation of other measures not included in EPA’s BSER calculation or compliance modeling, such as nuclear uprates, transmission system improvements, use of energy storage technologies or retrofit CCS, could also mitigate gas price and/or electricity price impacts.

The EPA projects coal production for use by the power sector, a large component of total coal production, will decline by roughly 25 to 27 percent in 2020 from base case levels. The
The use of coal by the power sector will decrease roughly 30 to 32 percent in 2030. Renewable energy capacity is anticipated to increase by roughly 12 GW in 2020 and by 9 GW in 2030 under Option 1. Energy market impacts from the guidelines are discussed more extensively in the RIA found in the docket for this rulemaking.

**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. These illustrative compliance scenarios are designed to reflect, to the extent possible, the scope and the nature of the proposed guidelines. However, there is considerable uncertainty with regards to the precise measures that states will adopt to meet the proposed requirements, because there are considerable
flexibilities afforded to the states in developing their state plans.

The EPA projects that the annual incremental compliance cost of Option 1 is estimated to be between $5.5 and $7.5 billion in 2020 and between $7.3 and $8.8 billion (2011$) in 2030, including the costs associated with monitoring, reporting, and recordkeeping (MRR). The incremental compliance cost of Option 2 is estimated to be between $4.3 and $5.5 billion in 2020, including MRR costs. In 2030, the estimated compliance cost of Option 2 is estimated to be between $1.9 and $3.1 billion (with the assumed levels of end-use energy efficiency). These important dynamics are discussed in more detail in the RIA in the rulemaking docket. The annualized incremental cost is the projected additional cost of complying with the guidelines in the year analyzed, and includes the amortized cost of capital investment, needed new capacity, shifts between or amongst various fuels, deployment of energy efficiency programs, and other actions associated with compliance. MRR costs are estimated to be $61.6 million (2011$) in 2020 for Options 1 and 2 and $8.2 million for both Options 1 and 2 in 2025 and 2030. More detailed cost estimates are available in the RIA included in the rulemaking docket.

F. What are the economic and employment impacts?
The proposed standards are projected to result in certain changes to power system operation as a result of the application of state emission rate goals. Overall, we project dispatch changes, changes to fossil fuel and retail electricity prices, and some additional coal retirements. Average electric power sector-delivered natural gas prices are projected to increase by roughly 9 to 12 percent in 2020 in Option 1, with negligible changes by 2030. Under Option 2, electric power sector natural gas prices are projected to increase by roughly 8 percent in 2020, on an average nationwide basis, and decrease in 2030. The average delivered coal price to the power sector is projected to decrease by 16 to 17 percent in 2020 under Option 1, and decrease by roughly 14 percent under Option 2, on a nationwide average basis. Retail electricity prices are projected to increase 6 to 7 percent under Option 1 and increase by roughly 4 percent under Option 2, both in 2020 and on an average basis across the contiguous U.S. By 2030 under Option 1, electricity prices are projected to increase by about 3 percent. Under Option 1, the EPA projects 46 to 50 GW of additional coal-fired generation may be uneconomic to maintain and may be removed from operation by 2030. The EPA projects that under Option 2, 30 to 33 GW of additional coal-fired generation may be uneconomic to maintain and may be removed from operation by 2030.
It is important to note that the EPA’s modeling does not necessarily account for all of the factors that may influence business decisions regarding future coal fired capacity. By 2025, the average age of the coal-fired fleet will be 49 years old and twenty percent of the fleet will be more than 60 years old. Many power companies already factor a carbon price into their long term capacity planning that would further influence business decisions to replace these aging assets with modern, and significantly cleaner generation.

The compliance modeling done to support the proposal assumes that overall electric demand will decrease significantly, as states ramp up programs that result in lower overall demand. End-use energy efficiency levels increase such that they achieve about an 11 percent reduction on overall electricity demand levels in 2030 for Option 1, and approximately an 8 percent reduction in 2030 for Option 2. In response, there are anticipated to be notable changes to costs, prices, and electricity generation in the power sector as more end-use efficiency is realized.

Changes in price or demand for electricity, natural gas, coal, can impact markets for goods and services produced by sectors that use these energy inputs in the production process or supply those sectors. Changes in cost of production may
result in changes in price, changes in quantity produced, and changes in profitability of firms affected. The EPA recognizes that these guidelines provide significant flexibilities and states implementing the guidelines may choose to mitigate impacts to some markets outside the EGU sector. Similarly, demand for new generation or energy efficiency can result in shifts in production and profitability for firms that supply those goods and services, and the guidelines provide flexibility for states that may want to enhance demand for goods and services from those sectors.

Executive Order 13563 directs federal agencies to consider the effect of regulations on job creation and employment. According to the Executive Order, “our regulatory system must protect public health, welfare, safety, and our environment while promoting economic growth, innovation, competitiveness, and job creation. It must be based on the best available science” (Executive Order 13563, 2011). Although standard benefit-cost analyses have not typically included a separate analysis of regulation-induced employment impacts, during periods of sustained high unemployment, employment impacts are of particular concern and questions may arise about their existence and magnitude.
States have the responsibility and flexibility to implement policies and practices for compliance with Proposed Electric Generating Unit Greenhouse Gas Existing Source Guidelines. Quantifying the associated employment impacts is complicated by the wide range of approaches that States may use. As such, EPA’s employment analysis includes projected employment impacts associated with illustrative compliance scenarios for these guidelines for the electric power industry, coal and natural gas production, and demand side energy efficiency activities. These projections are derived, in part, from a detailed model of the electricity production sector used for this regulatory analysis, and U.S government data on employment and labor productivity. In the electricity, coal, and natural gas sectors, the EPA estimates that these guidelines could have an employment impact of roughly 25,900 to 28,000 job-years increase in 2020 for Option 1, state to regional compliance approach, respectively. For Option 2, the state and regional compliance approach estimates are 26,700 to 29,800 job-years increase in 2020. Demand-side energy efficiency employment impacts are approximately an increase 78,800 jobs in 2020 for Option 1 and 57,000 increased jobs for Option 2. By its nature, energy efficiency reduces overall demand for electric power. The EPA recognizes as more efficiency is built into the U.S. power system over time, lower
fuel requirements may lead to fewer jobs in the coal and natural
gas extraction sectors, as well as in EGU construction and
operation than would otherwise have been expected. The EPA also
recognizes the fact that, in many cases, employment gains and
losses that might be attributable to this rule would be expected
to affect different sets of people. Moreover, workers who lose
jobs in these sectors may find employment elsewhere just as
workers employed in new jobs in these sectors may have been
previously employed elsewhere. Therefore the numbers reported in
these sectors may have been previously employed elsewhere.
Therefore the numbers reported here should not be interpreted as
a net national employment impact. G. What are the benefits of
the proposed goals?

Implementing the proposed standards will generate benefits
by reducing emissions of 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
estimated benefits associated with these emission reductions are
beyond those achieved by previous EPA rulemakings including the
Mercury and Air Toxics Standards. 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 $32 billion to $51 billion in 2020 and $54 billion to $86 billion in 2030 assuming a regional compliance approach (2011 dollars at a 3-percent discount rate [model average]). If states comply using a state-specific compliance approach, these climate and health co-benefits estimates are estimated to be $33 to $54 billion in 2020 and $56 to $89 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 $25 billion to $41 billion in 2020 and $35 billion to $56 billion in 2025 (regional compliance approach, 2011 dollars at a 3-percent discount rate [model average]). Assuming a state compliance approach, the total combined climate benefits and health co-benefits for Option 2 are estimated to be $26 billion to $42 billion in 2020 and $35 billion to $57 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 9 through 14 of this preamble.
### Table 9: Summary of the Monetized Global Climate Benefits for the Proposed Option 1 (billions of 2011 dollars)\(^a\)

<table>
<thead>
<tr>
<th>Discount Rate (Statistic)</th>
<th>Regional Compliance</th>
<th>State Compliance</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>2020</strong></td>
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<td></td>
</tr>
<tr>
<td>CO₂ Reductions (million metric tons)</td>
<td></td>
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</tr>
<tr>
<td>5 percent (average SCC)</td>
<td>$4.7</td>
<td>$4.1</td>
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<tr>
<td>3 percent (average SCC)</td>
<td>$17</td>
<td>$14</td>
</tr>
<tr>
<td>2.5 percent (average SCC)</td>
<td>$25</td>
<td>$23</td>
</tr>
<tr>
<td>3 percent (95(^{th}) percentile SCC)</td>
<td>$51</td>
<td>$54</td>
</tr>
<tr>
<td><strong>2025</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>CO₂ Reductions (million metric tons)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>5 percent (average SCC)</td>
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<td>$25</td>
</tr>
<tr>
<td>2.5 percent (average SCC)</td>
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<td>$37</td>
</tr>
<tr>
<td>3 percent (95(^{th}) percentile SCC)</td>
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<td>$76</td>
</tr>
<tr>
<td><strong>2030</strong></td>
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<td></td>
</tr>
<tr>
<td>CO₂ Reductions (million metric tons)</td>
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<td></td>
</tr>
<tr>
<td>5 percent (average SCC)</td>
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<td>$9.3</td>
</tr>
<tr>
<td>3 percent (average SCC)</td>
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<td>$30</td>
</tr>
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<td>2.5 percent (average SCC)</td>
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<td>$44</td>
</tr>
<tr>
<td>3 percent (95(^{th}) percentile SCC)</td>
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<td>$92</td>
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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 social cost of carbon (SCC) estimates for the analysis years (2020, 2025, 2030) and are rounded to two significant figures.
Table 10 Summary of the Monetized Global Climate Benefits for the Option 2 (billions of 2011 dollars)*

<table>
<thead>
<tr>
<th>Discount Rate (Statistic)</th>
<th>Monetized Climate Benefits</th>
<th>Regional Compliance</th>
<th>State Compliance</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
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<td></td>
<td></td>
</tr>
<tr>
<td>2020</td>
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<td></td>
<td></td>
</tr>
<tr>
<td>CO2 Reductions (million metric tons)</td>
<td>283</td>
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<tr>
<td>5 percent (average SCC)</td>
<td>$3.6</td>
<td></td>
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<td>3 percent (average SCC)</td>
<td>$13</td>
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<td>2.5 percent (average SCC)</td>
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<td>3 percent (95th percentile SCC)</td>
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<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2025</td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>CO2 Reductions (million metric tons)</td>
<td>368</td>
<td></td>
<td>376</td>
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<tr>
<td>5 percent (average SCC)</td>
<td>$5.5</td>
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<td></td>
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<tr>
<td>3 percent (average SCC)</td>
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<td></td>
<td></td>
</tr>
<tr>
<td>2.5 percent (average SCC)</td>
<td>$27</td>
<td></td>
<td></td>
</tr>
<tr>
<td>3 percent (95th percentile SCC)</td>
<td>$56</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2030</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>CO2 Reductions (million metric tons)</td>
<td>353</td>
<td></td>
<td>373</td>
</tr>
<tr>
<td>5 percent (average SCC)</td>
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<td>$6.4</td>
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<tr>
<td>3 percent (average SCC)</td>
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<td>$21</td>
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<tr>
<td>2.5 percent (average SCC)</td>
<td>$28</td>
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<td>$30</td>
</tr>
<tr>
<td>3 percent (95th percentile SCC)</td>
<td>$60</td>
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<td>$63</td>
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*Discounted benefits are calculated at 7 percent.
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 11 Summary of the Monetized Health Co-Benefits for the Proposed Standards Option 1 Regional Compliance Approach in the U.S. (billions of 2011 dollars)^a

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>National Emission Reductions (thousands of short tons)</th>
<th>Monetized Health Co-benefits (3 percent discount)</th>
<th>Monetized Health Co-benefits (7 percent discount)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Option 1 Regional Compliance Approach 2020</td>
<td></td>
<td></td>
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<tr>
<td>PM(_2.5) precursors b</td>
<td></td>
<td></td>
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<tr>
<td>SO(_2)</td>
<td>292</td>
<td>$12 to $26</td>
<td>$11 to $24</td>
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<tr>
<td>Directly emitted PM(_2.5) (Elemental Carbon and Organic Carbon)</td>
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<td></td>
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<tr>
<td>Directly emitted PM(_2.5) (crustal)</td>
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<tr>
<td>NO(_x) 345</td>
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<td>$2.2 to $5.0</td>
<td>$2.0 to $4.5</td>
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<tr>
<td>Ozone precursor c</td>
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<td></td>
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<tr>
<td>NO(_x) 146</td>
<td>$0.63 to $2.7</td>
<td>$0.63 to $2.7</td>
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<tr>
<td>Total Monetized Health Co-benefits</td>
<td>$15 to $34</td>
<td>$13 to $31</td>
<td></td>
</tr>
<tr>
<td>Total Monetized Health Co-benefits combined with Monetized Climate Benefits d</td>
<td>$32 to $51</td>
<td>$30 to $48</td>
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</tr>
<tr>
<td>Option 1 Regional Compliance Approach 2025</td>
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</tr>
<tr>
<td>PM(_2.5) precursors b</td>
<td></td>
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<tr>
<td>SO(_2) 395</td>
<td></td>
<td>$17 to $38</td>
<td>$15 to $35</td>
</tr>
<tr>
<td>Directly emitted PM(_2.5) (Elemental Carbon and Organic Carbon)</td>
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<tr>
<td>Directly emitted PM(_2.5) (crustal)</td>
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<tr>
<td>NO(_x) 421</td>
<td>$3.0 to $6.8</td>
<td>$2.7 to $6.1</td>
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<td>Ozone precursor c</td>
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<tr>
<td>NO(_x) 180</td>
<td>$1.0 to $4.3</td>
<td>$1.0 to $4.3</td>
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<td>Total Monetized Health Co-benefits</td>
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<td>$44 to $70</td>
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<td>-------------</td>
<td></td>
</tr>
<tr>
<td>combined with Monetized Climate</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Benefits d</td>
<td></td>
<td></td>
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</tr>
<tr>
<td><strong>Option 1 Regional Compliance Approach 2030</strong></td>
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<td>PM$_2.5$ precursors b</td>
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<tr>
<td>SO$_2$</td>
<td>424</td>
<td>$20 to $44</td>
<td>$18 to $40</td>
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<td>Directly emitted PM$_2.5$ (Elemental Carbon and Organic Carbon)</td>
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<tr>
<td>Directly emitted PM$_2.5$ (crustal)</td>
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<td></td>
<td></td>
</tr>
<tr>
<td>NO$_x$</td>
<td>407</td>
<td>$3.0 to $6.7</td>
<td>$2.7 to $6.1</td>
</tr>
<tr>
<td>Ozone precursor c</td>
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<td></td>
<td></td>
</tr>
<tr>
<td>NO$_x$</td>
<td>176</td>
<td>$1.1 to $4.5</td>
<td>$1.1 to $4.5</td>
</tr>
<tr>
<td>Total Monetized Health Co-benefits</td>
<td>$24 to $55</td>
<td>$21 to $50</td>
<td></td>
</tr>
<tr>
<td>combined with Monetized Climate</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Benefits d</td>
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<td></td>
</tr>
<tr>
<td>$54 to $86</td>
<td>$52 to $81</td>
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</table>

a. [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.
The monetized ozone co-benefits reflect the human health benefits associated with reducing exposure to ozone through reductions of NOx 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.

We estimate climate benefits associated with four different values of a one ton CO2 reduction (model average at 2.5 percent discount rate, 3 percent, and 5 percent; 95th percentile at 3 percent), which each increase over time. For the purposes of this table, we show the benefits associated with the model average at 3% discount rate, however we emphasize the importance and value of considering the full range of SCC values. We provide combined climate and health estimates based on additional discount rates in the RIA.
### Table 12 Summary of the Monetized Health Co-Benefits in the U.S. for the Proposed Guidelines Option 1 State Compliance Approach (billions of 2011 dollars) 

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>National Emission Reductions (thousands of short tons)</th>
<th>Monetized Health Co-benefits (3 percent discount)</th>
<th>Monetized Health Co-benefits (7 percent discount)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Option 1 State Compliance Approach in 2020</strong></td>
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<tr>
<td>PM2.5 precursors</td>
<td></td>
<td></td>
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<tr>
<td>SO2</td>
<td>335</td>
<td>$13 to $29</td>
<td>$11 to $26</td>
</tr>
<tr>
<td>Directly emitted PM2.5 (Elemental Carbon and Organic Carbon)</td>
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<td></td>
<td></td>
</tr>
<tr>
<td>Directly emitted PM2.5 (crustal)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>NOx</td>
<td>367</td>
<td>$2.2 to $4.9</td>
<td>$2.0 to $4.4</td>
</tr>
<tr>
<td>Ozone precursor c</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>NOx</td>
<td>157</td>
<td>$0.64 to $2.7</td>
<td>$0.64 to $2.7</td>
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<td><strong>Total Monetized Health Co-benefits</strong></td>
<td></td>
<td>$15 to $36</td>
<td>$14 to $33</td>
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<tr>
<td><strong>Total Monetized Health Co-benefits combined with Monetized Climate Benefits</strong></td>
<td></td>
<td>$33 to $54</td>
<td>$32 to $50</td>
</tr>
<tr>
<td><strong>Option 1 State Compliance Approach in 2025</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>PM2.5 precursors</td>
<td></td>
<td></td>
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</tr>
<tr>
<td>SO2</td>
<td>425</td>
<td>$18 to $40</td>
<td>$16 to $36</td>
</tr>
<tr>
<td>Directly emitted PM2.5 (Elemental Carbon and Organic Carbon)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Directly emitted PM2.5 (crustal)</td>
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<td></td>
<td></td>
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<tr>
<td>NOx</td>
<td>436</td>
<td>$2.9 to $6.5</td>
<td>$2.6 to $5.8</td>
</tr>
<tr>
<td>Ozone precursor c</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>NOx</td>
<td>190</td>
<td>$1.0 to $4.4</td>
<td>$1.0 to $4.4</td>
</tr>
<tr>
<td><strong>Total Monetized Health Co-benefits</strong></td>
<td></td>
<td>$22 to $51</td>
<td>$20 to $46</td>
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</table>
### Total Monetized Health Co-benefits combined with Monetized Climate Benefits $^d$

<table>
<thead>
<tr>
<th></th>
<th>Option 1 State Compliance Approach in 2030</th>
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</thead>
<tbody>
<tr>
<td>PM$_{2.5}$ precursors $^b$</td>
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</tr>
<tr>
<td>SO$_2$</td>
<td>$471$</td>
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<tr>
<td>Directly emitted PM$_{2.5}$ (Elemental Carbon and Organic Carbon)</td>
<td>$21 to $47$</td>
</tr>
<tr>
<td>Directly emitted PM$_{2.5}$ (crustal)</td>
<td></td>
</tr>
<tr>
<td>NO$_x$</td>
<td>$428$</td>
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<tr>
<td>Ozone precursor $^c$</td>
<td></td>
</tr>
<tr>
<td>NO$_x$</td>
<td>$187$</td>
</tr>
</tbody>
</table>

| Total Monetized Health Co-benefits combined with Monetized Climate Benefits $^d$ | $25 to $58$ | $23 to $53$ |
| Total Monetized Health Co-benefits combined with Monetized Climate Benefits $^d$ | $56 to $89$ | $53 to $84$ |

$^a$ 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$_x$, 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 NOX 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 CO2 reduction (model average at 2.5 percent discount rate, 3 percent, and 5 percent; 95th percentile at 3 percent), which each increase over time. For the purposes of this table, we show the benefits associated with the model average at 3% discount rate, however we emphasize the importance and value of considering the full range of SCC values. We provide combined climate and health estimates based on additional discount rates in the RIA.
### Table 13 Summary of the Monetized Health Co-Benefits in the U.S. for the Option 2 Regional Compliance Approach (billions of 2011 dollars)\(^a\)

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>National Emission Reductions (thousands of short tons)</th>
<th>Monetized Health Co-benefits (3 percent discount)</th>
<th>Monetized Health Co-benefits (7 percent discount)</th>
</tr>
</thead>
<tbody>
<tr>
<td>PM(_{2.5}) precursors (^b)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>SO(_2)</td>
<td>244</td>
<td>$9.8 to $22</td>
<td>$8.9 to $20</td>
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<tr>
<td>Directly emitted PM(_{2.5}) (Elemental Carbon and Organic Carbon)</td>
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<td></td>
<td></td>
</tr>
<tr>
<td>NO(_x)</td>
<td>268</td>
<td>$1.7 to $3.9</td>
<td>$1.6 to $3.5</td>
</tr>
<tr>
<td>Directly emitted PM(_{2.5}) (crustal)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Ozone precursor (^c)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>NO(_x)</td>
<td>111</td>
<td>$0.47 to $2.0</td>
<td>$0.47 to $2.0</td>
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<tr>
<td>Total Monetized Health Co-benefits</td>
<td></td>
<td>$12 to $28</td>
<td>$11 to $25</td>
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<tr>
<td>Total Monetized Health Co-benefits combined with Monetized Climate Benefits (^d)</td>
<td></td>
<td>$25 to $41</td>
<td>$24 to $38</td>
</tr>
<tr>
<td>PM(_{2.5}) precursors (^b)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>SO(_2)</td>
<td></td>
<td>$13 to $29</td>
<td>$12 to $26</td>
</tr>
<tr>
<td>Directly emitted PM(_{2.5}) (Elemental Carbon and Organic Carbon)</td>
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<td>297</td>
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<tr>
<td>Directly emitted PM(_{2.5}) (crustal)</td>
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<tr>
<td>NO(_x)</td>
<td>309</td>
<td>$2.2 to $5.0</td>
<td>$2.0 to $4.5</td>
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<tr>
<td>Ozone precursor (^c)</td>
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<td></td>
<td></td>
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<tr>
<td>NO(_x)</td>
<td>129</td>
<td>$0.73 to $3.1</td>
<td>$0.73 to $3.1</td>
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<td>Total Monetized Health Co-benefits</td>
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<td>$16 to $37</td>
<td>$14 to $34</td>
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<tr>
<td>Total Monetized Health Co-benefits combined with Monetized Climate Benefits</td>
<td>$34 to $56</td>
<td>$33 to $52</td>
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<tr>
<td>-------------------------------</td>
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</tr>
<tr>
<td><strong>Option 2 Regional Compliance Approach in 2030</strong></td>
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<tr>
<td><strong>PM$_{2.5}$ precursors $^b$</strong></td>
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<tr>
<td>SO$_2$</td>
<td>287</td>
<td>$13 to $30</td>
<td>$12 to $27</td>
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<td>Directly emitted PM$_{2.5}$ (Elemental Carbon and Organic Carbon)</td>
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<td></td>
<td></td>
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<tr>
<td>Directly emitted PM$_{2.5}$ (crustal)</td>
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<tr>
<td>NO$_x$</td>
<td>252</td>
<td>$1.8 to $4.2</td>
<td>$1.7 to $3.8</td>
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<td>Ozone precursor $^c$</td>
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<tr>
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<td>110</td>
<td>$0.66 to $2.8</td>
<td>$0.66 to $2.8</td>
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<td><strong>Total Monetized Health Co-benefits</strong></td>
<td>$16 to $37</td>
<td>$14 to $34</td>
<td></td>
</tr>
<tr>
<td><strong>Total Monetized Health Co-benefits combined with Monetized Climate Benefits $^d$</strong></td>
<td>$35 to $56</td>
<td>$34 to $53</td>
<td></td>
</tr>
</tbody>
</table>

$^a$ [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$_x$, ecosystem effects or visibility impairment. Air pollution health co-benefits are estimated using regional benefit-per-ton estimates for the contiguous U.S.

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.

$^b$ The monetized PM$_{2.5}$ co-benefits reflect the human health benefits associated with reducing exposure to ozone through...
reductions of NOX 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.

We estimate climate benefits associated with four different values of a one ton CO2 reduction (model average at 2.5 percent discount rate, 3 percent, and 5 percent; 95th percentile at 3 percent), which each increase over time. For the purposes of this table, we show the benefits associated with the model average at 3% discount rate, however we emphasize the importance and value of considering the full range of SCC values. We provide combined climate and health estimates based on additional discount rates in the RIA.

Table 14 Summary of the Monetized Health Co-Benefits in the U.S. for Option 2 State Compliance Approach (billions of 2011 dollars)\(^a\)

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>National Emission Reductions (thousands of 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>PM2.5 precursors(^b)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>SO2</td>
<td>267</td>
<td>$10 to $23</td>
<td>$9.1 to $21</td>
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<td>Directly emitted PM2.5 (Elemental Carbon and Organic Carbon)</td>
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<td>281</td>
<td>$1.7 to $3.8</td>
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<td>119</td>
<td>$0.48 to $2.1</td>
<td>$0.48 to $2.1</td>
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<tr>
<td>Ozone precursor (^c)</td>
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<td></td>
</tr>
<tr>
<td>NOx</td>
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<td>$0.48 to $2.1</td>
<td>$0.48 to $2.1</td>
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<tr>
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<td>$12 to $29</td>
<td>$11 to $26</td>
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<tr>
<td>---------------------</td>
<td>------------------------------------------</td>
<td>---------------------</td>
<td>---------------------</td>
</tr>
<tr>
<td>Total Monetized Health Co-benefits combined with Monetized Climate Benefits</td>
<td>$26 to $42</td>
<td>$25 to $40</td>
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<tr>
<td>PM$_{2.5}$ precursors</td>
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<tr>
<td>SO$_2$</td>
<td>327</td>
<td>$14 to $30</td>
<td>$12 to $27</td>
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<td>Directly emitted PM$_{2.5}$ (Elemental Carbon and Organic Carbon)</td>
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<tr>
<td>Directly emitted PM$_{2.5}$ (crustal)</td>
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</tr>
<tr>
<td>NO$_x$</td>
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<tr>
<td>NO$_x$</td>
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<td>$0.72 to $3.1</td>
<td>$0.72 to $3.1</td>
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<td>$16 to $38</td>
<td>$15 to $35</td>
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</tr>
<tr>
<td>Total Monetized Health Co-benefits combined with Monetized Climate Benefits</td>
<td>$35 to $57</td>
<td>$34 to $54</td>
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</table>

<table>
<thead>
<tr>
<th></th>
<th>Option 2 State Compliance Approach in 2030</th>
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</tr>
</thead>
<tbody>
<tr>
<td>Total Monetized Health Co-benefits combined with Monetized Climate Benefits</td>
<td>$26 to $42</td>
<td>$25 to $40</td>
<td></td>
</tr>
<tr>
<td>PM$_{2.5}$ precursors</td>
<td></td>
<td></td>
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<tr>
<td>SO$_2$</td>
<td>321</td>
<td>$14 to $32</td>
<td>$13 to $29</td>
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<td>Directly emitted PM$_{2.5}$ (Elemental Carbon and Organic Carbon)</td>
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<tr>
<td>Directly emitted PM$_{2.5}$ (crustal)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>NO$_x$</td>
<td>274</td>
<td>$1.9 to $4.2</td>
<td>$1.7 to $3.8</td>
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<tr>
<td>NO$_x$</td>
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<td>$0.68 to $2.9</td>
<td>$0.68 to $2.9</td>
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<tr>
<td>Total Monetized Health Co-benefits</td>
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<td>$15 to $36</td>
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</tr>
<tr>
<td>Total Monetized Health Co-benefits combined with Monetized Climate Benefits</td>
<td>$37 to $60</td>
<td>$36 to $56</td>
<td></td>
</tr>
</tbody>
</table>

*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 SO2, direct exposure to NOx, ecosystem effects or visibility impairment. Air pollution health co-benefits are estimated using regional benefit-per-ton estimates for the contiguous U.S.

The monetized PM2.5 co-benefits reflect the human health benefits associated with reducing exposure to PM2.5 through reductions of PM2.5 precursors, such as SO2, NOx and directly emitted PM2.5. 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.

The monetized ozone co-benefits reflect the human health benefits associated with reducing exposure to ozone through reductions of NOx 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.

We estimate climate benefits associated with four different values of a one ton CO2 reduction (model average at 2.5 percent discount rate, 3 percent, and 5 percent; 95th percentile at 3 percent), which each increase over time. For the purposes of this table, we show the benefits associated with the model average at 3% discount rate; however, we emphasize the importance and value of considering the full range of SCC values. We provide combined climate and health estimates based on additional discount rates in the RIA.

The EPA has used the U.S. government’s SCC estimates to analyze CO2 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 (IAM) to develop SCC estimates and selected...
four global values for use in regulatory analyses. The U.S. government recently updated these estimates using new versions of each integrated assessment model and published them in 2013. The 2013 update did not revisit the 2010 modeling decisions (e.g., with regard to the discount rate, reference case socioeconomic and emission scenarios or equilibrium climate sensitivity). Rather, improvements in the way damages are modeled are confined to those that have been incorporated into the latest versions of the models by the developers themselves and published in the peer-reviewed literature. The 2010 SCC Technical Support Document (2010 SCC TSD) provides a complete discussion of the methods used to develop these estimates and the 2013 SCC TSD presents and discusses the updated estimates.295,296


The 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). 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 over time).


by different generations). The fourth value is the 95\textsuperscript{th} percentile of the SCC from all three models at a 3 percent discount rate. It is included to represent higher-than-expected impacts from temperature change further out in the tails of the SCC distribution (representing less likely, but potentially catastrophic, outcomes).

The 2010 SCC TSD noted a number of limitations to the SCC analysis, including the incomplete way in which the integrated assessment models capture catastrophic and non-catastrophic impacts, their incomplete treatment of adaptation and technological change, uncertainty in the extrapolation of damages to high temperatures, and assumptions regarding risk aversion. Current integrated assessment models do not assign value to all of the important physical, ecological, and economic impacts of climate change recognized in the climate change literature for various reasons, including the inherent difficulties in valuing non-market impacts and the fact that the science incorporated into these models understandably lags behind the most recent research. Nonetheless, these estimates and the discussion of their limitations represent the best available information about the social benefits of CO\textsubscript{2} emission reductions to inform the benefit-cost analysis. Model developers continually update the models to incorporate recent research.
The new versions of the models used to estimate the values presented in this rulemaking offer some improvements in these areas identified above, although further work is warranted. Accordingly, the EPA and other parties continue to conduct research on modeling and valuation of climate impacts with the goal of improving these estimates. Additional details are provided in the SCC TSDs.

The health co-benefits estimates represent the total monetized human health benefits for populations exposed to reduced PM$_{2.5}$ and ozone resulting from emission reductions under illustrative compliance options for the proposed standards. Unlike the global SCC estimates, the air pollution health co-benefits are estimated for the contiguous U.S. only. We used a “benefit-per-ton” approach to estimate the benefits of this rulemaking. To create the PM$_{2.5}$ benefit-per-ton estimates, this approach uses a model to convert emissions of PM$_{2.5}$ precursors into changes in ambient PM$_{2.5}$ levels and another model to estimate the changes in human health 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

**Deleted:** Because we were unable to conduct air quality modeling for this rule, we instead
et al. (2012), but they have since been updated to reflect the studies and population data in the 2012 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

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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 PM2.5 levels, which drive population exposure.

It is important to note that the magnitude of the PM2.5 and ozone co-benefits is largely driven by the concentration response functions for premature mortality and the value of a

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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{303} and the extended Six Cities cohort study.\textsuperscript{304} We present the PM$_{2.5}$ co-benefits results as a range based on the concentration-response functions from these two epidemiology studies, but this range does not capture the full range of uncertainty inherent in the co-benefits estimates. In the RIA for this rule, which is available in the docket, we also include PM$_{2.5}$ co-benefits estimates derived from expert judgments (Roman et al., 2008)\textsuperscript{305} as a characterization of uncertainty regarding the PM$_{2.5}$-mortality relationship. For the ozone co-benefits, we present the results as a range reflecting the use of several different concentration-response functions for mortality, with the lower

\begin{itemize}
\end{itemize}
end of the range based on a function from Bell et al. (2004)\textsuperscript{306} and the upper end based on a function from Levy et al. (2005)\textsuperscript{307}.

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 Integrated Science Assessment for Particulate Matter,\textsuperscript{308} 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$_{2.5}$ 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$^{309}$ 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.

$^{309}$ In addition, site-specific emission reductions will depend upon how states implement the guidelines.
in the health impact function, along with baseline incidence rates, population, and change in air quality. Therefore, caution is warranted when interpreting the LML assessment for this rule because these results are not consistent with results from rules that had air quality modeling.

Every benefit analysis examining the potential effects of a change in environmental protection requirements is limited, to some extent, by data gaps, model capabilities (such as geographic coverage) and uncertainties in the underlying scientific and economic studies used to configure the benefit and cost models. Despite these uncertainties, we believe the air quality co-benefit analysis for this rule provides a reasonable indication of the expected health benefits of the air pollution emission reductions for the illustrative compliance options for the proposed standards under a set of reasonable assumptions. This analysis does not include the type of detailed uncertainty assessment found in the 2012 PM$_{2.5}$ National Ambient Air Quality Standard (NAAQS) RIA (U.S. EPA, 2012) because we lack the necessary air quality input and monitoring data to conduct a complete benefits assessment. In addition, using a benefit-per-ton approach adds another important source of uncertainty to the benefits estimates. The 2012 PM$_{2.5}$ NAAQS benefits analysis provides an indication of the sensitivity of our results to
various assumptions.

We note that the monetized co-benefits estimates shown here do not include several important benefit categories, including exposure to 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 rulemaking docket.

XI. Statutory and Executive Order Reviews

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

Under Section 3(f)(1) of Executive Order 12866 (58 FR 51735, October 4, 1993), this action is an "economically significant regulatory action" because it is likely to have an annual effect on the economy of $100 million or more or adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or state, local, or tribal governments
or communities. The $100 million threshold can be triggered by either costs or benefits, or a combination of them. Accordingly, the EPA submitted this action to OMB for review under Executive Orders 12866 and 13563 (76 FR 3821, January 21, 2011), and any changes made in response to OMB recommendations have been documented in the docket for this action.

The EPA also prepared an analysis of the potential costs and benefits associated with this action. This analysis is contained in the RIA for this proposed rule. A copy of the analysis is available in the docket for this action.

Consistent with EO 12866 and EO 13563, the EPA estimated the costs and benefits for illustrative compliance approaches of implementing the proposed guidelines. This proposal sets goals to reduce 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. For the regional compliance approach, the EPA estimates that in 2020 this Option 1 proposal will yield monetized climate benefits (in 2011$) of approximately $17 billion (3 percent model average). The air pollution health co-benefits in 2020 are estimated to be $15 billion to $34 billion (2011$) for a 3 percent discount rate and $13 billion to $31 billion (2011$) for a 7 percent discount rate. The annual, illustrative compliance costs estimated by IPM and inclusive of demand side energy efficiency program and participant costs and MRR costs, are approximately $5.5 billion (2011$) in 2020. The quantified net benefits (the difference between monetized benefits and costs) in 2020 are estimated to be $26 billion to $46 billion assuming a regional compliance approach (2011$) using a 3 percent discount rate (model average). This range of net benefits is also estimated to be $26 billion to $45 billion assuming a state compliance approach (2011$) using a 3 percent discount rate (model average). Table 15 shows the climate benefits, health co-benefits, cost and net
benefits for Option 1 in 2020 for state and regional compliance approaches. Table 16 shows similar estimates for 2030.

For Option 1 in 2030 assuming a regional compliance approach, the EPA estimates this proposal will yield monetized climate benefits (in 2011$) of approximately $30 billion (3 percent, model average). The air pollution health co-benefits in 2030 are estimated to be $24 billion to $55 billion (2011$) for a 3 percent discount rate and $21 billion to $50 billion (2011$) for a 7 percent discount rate. The annual illustrative compliance costs estimated using IPM, inclusive of a demand-side energy efficiency program and participant costs and MRR costs, are approximately $7.3 billion (2011$) in 2030. The quantified net benefits (the difference between monetized benefits and costs) in 2030 are estimated to be $47 billion to $78 billion (2011$) using a 3 percent discount rate (model average). The EPA estimates that this proposal will yield monetized climate benefits (in 2011$) of approximately $31 billion (3 percent, model average) for Option 1 state compliance approach in 2030. The air pollution health co-benefits in 2030 are estimated to be $25 billion to $58 billion (2011$) for a 3 percent discount rate and $23 billion to $53 billion (2011$) for a 7 percent discount rate. The annual illustrative compliance costs estimated using IPM, inclusive of demand side energy efficiency program and
Participant costs and MRR costs, are approximately $8.8 billion (2011$) in 2030. The quantified net benefits (the difference between monetized benefits and costs) in 2030 are estimated to be $47 billion to $80 billion (2011$) using a 3 percent discount rate (model average) assuming a state compliance approach. Based upon the foregoing discussion, it remains clear that the benefits of the proposal Option 1 are substantial and far exceed the costs.

TABLE 15—SUMMARY OF THE MONETIZED BENEFITS, COMPLIANCE COSTS, AND NET BENEFITS FOR THE FINAL RULE – OPTION 1 IN 2020a

<table>
<thead>
<tr>
<th>Option 1 Regional Compliance Approach</th>
<th>3% Discount rate</th>
<th>7% Discount rate</th>
</tr>
</thead>
<tbody>
<tr>
<td>Climate benefits b</td>
<td>$17</td>
<td></td>
</tr>
<tr>
<td>Air pollution health co-benefits c</td>
<td>$15 to $34</td>
<td>$13 to $31</td>
</tr>
<tr>
<td>Total Compliance Costs d</td>
<td>$5.5</td>
<td>$5.5</td>
</tr>
<tr>
<td>Net Monetized Benefits e</td>
<td>$26 to $45</td>
<td>$25 to $42</td>
</tr>
<tr>
<td>Non-monetized Benefits</td>
<td>Direct exposure to SO\textsubscript{2} and NO\textsubscript{2}</td>
<td>1.3 tons of Hg</td>
</tr>
</tbody>
</table>

Ecosystem Effects
### Option 1 State Compliance Approach

<table>
<thead>
<tr>
<th></th>
<th>Visibility impairment</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Climate benefits</strong></td>
<td>$18</td>
</tr>
<tr>
<td><strong>Air pollution health</strong></td>
<td>$15 to $36</td>
</tr>
<tr>
<td><strong>co-benefits</strong></td>
<td>$14 to $33</td>
</tr>
<tr>
<td><strong>Total Compliance</strong></td>
<td>$7.5</td>
</tr>
<tr>
<td><strong>Costs</strong></td>
<td>$7.5</td>
</tr>
<tr>
<td><strong>Net Monetized Benefits</strong></td>
<td>$26 to $46</td>
</tr>
<tr>
<td><strong>$24 to $43</strong></td>
<td></td>
</tr>
</tbody>
</table>

- **Direct exposure to SO₂ and NO₂**
- 1.5 tons
- **Ecosystem Effects**
- **Visibility impairment**

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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 PM$_{2.5}$ and ozone. These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because the scientific evidence is not yet sufficient to allow differentiation of effect estimates by particle type.

d Total costs are approximated by the illustrative compliance costs estimated using the Integrated Planning Model for the proposed option and a discount rate of approximately 5%. 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 16—SUMMARY OF THE MONETIZED BENEFITS, COMPLIANCE COSTS, AND NET BENEFITS FOR THE FINAL RULE – OPTION 1 IN 2030

[Billions of 2011$]

<table>
<thead>
<tr>
<th>Option 1 Regional Compliance Approach</th>
<th>3% Discount rate</th>
<th>7% Discount rate</th>
</tr>
</thead>
<tbody>
<tr>
<td>Climate benefits $^b$</td>
<td>$30</td>
<td></td>
</tr>
<tr>
<td>Air pollution health co-benefits $^c$</td>
<td>$24 to $55</td>
<td>$21 to $50</td>
</tr>
<tr>
<td>Total Compliance Costs $^d$</td>
<td>$7.3</td>
<td>$7.3</td>
</tr>
<tr>
<td>Net Monetized Benefits $^e$</td>
<td>$47 to $78</td>
<td>$44 to $73</td>
</tr>
<tr>
<td>Non-monetized Benefits</td>
<td>Direct exposure to SO$_2$ and NO$_2$</td>
<td></td>
</tr>
<tr>
<td></td>
<td>1.7 tons of Hg and 580 tons of HCl</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Ecosystem Effects</td>
<td></td>
</tr>
</tbody>
</table>

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<table>
<thead>
<tr>
<th>Visibility impairment</th>
<th>Option 1 State Compliance Approach</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Climate benefits</strong> b</td>
<td>$31</td>
</tr>
<tr>
<td><strong>Air pollution health co-benefits</strong> c</td>
<td>$25 to $58</td>
</tr>
<tr>
<td><strong>Total Compliance Costs</strong> d</td>
<td>$8.8</td>
</tr>
<tr>
<td><strong>Net Monetized Benefits</strong> e</td>
<td>$47 to $80</td>
</tr>
<tr>
<td><strong>Non-monetized Benefits</strong></td>
<td>Direct exposure to SO₂ and NO₂</td>
</tr>
<tr>
<td></td>
<td>2.1 tons of Hg and 590 tons of HCl</td>
</tr>
<tr>
<td></td>
<td>Ecosystem Effects</td>
</tr>
<tr>
<td></td>
<td>Visibility impairment</td>
</tr>
</tbody>
</table>

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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 PM$_{2.5}$ and ozone. These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because the scientific evidence is not yet sufficient to allow differentiation of effect estimates by particle type.

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

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

The estimated costs and benefits for the regulatory alternative - Option 2 regional and state compliance approaches are shown in Tables 17 and 18. As these tables reflect, net benefits in 2020 are estimated to be $21 to $37 billion (3 percent discount rate) and $20 to $34 billion (7 percent discount rate) for Option 2 assuming regional compliance. These Option 2 net benefit estimates become $20 to $37 billion (3 percent discount rate) and $19 to $34 billion (7 percent discount rate) with the state compliance approach. In 2025, net benefits are estimated to be $30 billion to $51 billion (3 percent discount rate) and from $28 billion to $48 billion (7 percent discount rate) assuming a regional compliance approach and $30 billion to $52 billion (3 percent discount rate) and from $28 billion to $48 billion (7 percent discount rate) assuming a state compliance approach.
The EPA could not monetize important benefits of proposed Option 1 and regulatory alternative Option 2. Unquantified benefits include climate benefits from reducing emissions of non-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 17 — SUMMARY OF THE MONETIZED BENEFITS, COMPLIANCE COSTS, AND NET BENEFITS FOR THE FINAL RULE – OPTION 2 IN 2020**

<table>
<thead>
<tr>
<th></th>
<th>3% Discount rate</th>
<th>7% Discount rate</th>
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</thead>
<tbody>
<tr>
<td>Climate benefits</td>
<td>$13</td>
<td></td>
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<tr>
<td>Air pollution health co-benefits</td>
<td>$12 to $28</td>
<td>$11 to $25</td>
</tr>
<tr>
<td>Total Compliance Costs</td>
<td>$4.3</td>
<td>$4.3</td>
</tr>
<tr>
<td>Net Monetized Benefits</td>
<td>$21 to $37</td>
<td>$20 to $34</td>
</tr>
<tr>
<td>Non-monetized Benefits</td>
<td>Direct exposure to SO₂ and NO₂</td>
<td></td>
</tr>
<tr>
<td></td>
<td>0.9 tons of Hg</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Ecosystem Effects</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Visibility impairment</td>
<td></td>
</tr>
</tbody>
</table>

[Billions of 2011]
### Option 2 State Compliance Approach

<p>| | | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Climate benefits</strong></td>
<td>$14</td>
<td></td>
</tr>
<tr>
<td><strong>Air pollution health</strong></td>
<td>$12 to $29</td>
<td>$11 to $26</td>
</tr>
<tr>
<td><strong>co-benefits</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Total Compliance Costs</strong></td>
<td>$5.5</td>
<td>$5.5</td>
</tr>
<tr>
<td><strong>Net Monetized Benefits</strong></td>
<td>$20 to $37</td>
<td>$19 to $34</td>
</tr>
<tr>
<td><strong>Non-monetized Benefits</strong></td>
<td>Direct exposure to SO$_2$ and NO$_x$</td>
<td>1.2 tons of Hg</td>
</tr>
<tr>
<td></td>
<td>Ecosystem Effects</td>
<td>Visibility impairment</td>
</tr>
</tbody>
</table>

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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 CO$_2$ emission changes and does not account for changes in non-CO$_2$ GHG emissions. Also, different discount rates are applied to SCC than to the other estimates because CO$_2$ emissions are long-lived and subsequent damages occur over many years. The benefit estimates in this table are based on the average SCC estimated 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; 95$^{th}$ percentile at 3 percent). The SCC estimates are year-specific and increase over time.

**c** The air pollution health co-benefits reflect reduced exposure to PM$_{2.5}$ and ozone associated with emission reductions of directly emitted PM$_{2.5}$, SO$_2$ and NO$_x$. The range reflects the use of concentration-response functions from different epidemiology studies. The reduction in premature fatalities each year...
accounts for over 90 percent of total monetized co-benefits from 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 18 — SUMMARY OF THE MONETIZED BENEFITS, COMPLIANCE COSTS, AND NET BENEFITS FOR THE FINAL RULE – OPTION 2 IN 2025$^a$ (Billions of 2011$)

<table>
<thead>
<tr>
<th>Option 2 Regional Compliance Approach</th>
<th>3% Discount rate</th>
<th>7% Discount rate</th>
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</thead>
<tbody>
<tr>
<td>Climate benefits $^b$</td>
<td>$16</td>
<td>$18</td>
</tr>
<tr>
<td>Air pollution health co-benefits $^c$</td>
<td>$16 to $37</td>
<td>$14 to $34</td>
</tr>
<tr>
<td>Total Compliance Costs $^d$</td>
<td>$4.5</td>
<td>$4.5</td>
</tr>
<tr>
<td>Net Monetized Benefits $^e$</td>
<td>$30 to $51</td>
<td>$28 to $48</td>
</tr>
<tr>
<td>Non-monetized Benefits</td>
<td>Direct exposure to SO₂ and NOₓ, 1.3 tons of Hg, Ecosystem Effects</td>
<td>1.3 tons of Hg,</td>
</tr>
<tr>
<td>Option 2 State Compliance Approach</td>
<td>Visibility impairment</td>
<td></td>
</tr>
<tr>
<td>-----------------------------------</td>
<td>-----------------------</td>
<td></td>
</tr>
<tr>
<td>Climate benefits (^b)</td>
<td>$19</td>
<td></td>
</tr>
<tr>
<td>Air pollution health co-benefits (^c)</td>
<td>$16 to $38</td>
<td>$15 to $35</td>
</tr>
<tr>
<td>Total Compliance Costs (^d)</td>
<td>$5.5</td>
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</tr>
<tr>
<td>Net Monetized Benefits (^e)</td>
<td>$30 to $52</td>
<td></td>
</tr>
<tr>
<td>Non-monetized Benefits</td>
<td>Direct exposure to SO(_2) and NO(_2)</td>
<td></td>
</tr>
<tr>
<td></td>
<td>1.7 tons of Hg</td>
<td></td>
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<tr>
<td></td>
<td>Ecosystem Effects</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Visibility impairment</td>
<td></td>
</tr>
</tbody>
</table>

\(^a\) All estimates are for 2025, and are rounded to two significant figures, so figures may not sum.

\(^b\) The climate benefit estimate in this summary table reflects global impacts from CO\(_2\) emission changes and does not account for changes in non-CO\(_2\) GHG emissions. Also, different discount rates are applied to SCC than to the other estimates because CO\(_2\) emissions are long-lived and subsequent damages occur over many years. The benefit estimates in this table are based on the average SCC estimated 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; 95\(^{th}\) percentile at 3 percent). The SCC estimates are year-specific and increase over time.

\(^c\) The air pollution health co-benefits reflect reduced exposure to PM\(_{2.5}\) and ozone associated with emission reductions of directly emitted PM\(_{2.5}\), SO\(_2\) and NO\(_x\). The range reflects the use of...
concentration-response functions from different epidemiology studies. The reduction in premature fatalities each year accounts for over 90 percent of total monetized co-benefits from PM$_{2.5}$ and ozone. These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because the scientific evidence is not yet sufficient to allow differentiation of effect estimates by particle type.

d Total costs are approximated by the illustrative compliance costs estimated using the Integrated Planning Model for the proposed option and a discount rate of approximately 5%. 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.

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 CO$_2$ emissions from existing sources in the power sector. These recordkeeping and reporting requirements are specifically authorized by CAA section 114 (42 U.S.C. 7414). All information submitted to the EPA pursuant to the recordkeeping and reporting requirements for
which a claim of confidentiality is made is safeguarded according to agency policies set forth in 40 CFR part 2, subpart B.

The annual burden for this collection of information for the states (averaged over the first 3 years following promulgation of this proposed action) is estimated to be a range of 315,554 hours at a total annual labor cost of $22,334,119, to 632,338 hours at a total annual labor cost of $44,755,317. The lower bound estimate reflects the assumption that some states already have energy efficiency and renewable energy programs in place. The higher bound estimate reflects the assumption that no states have energy efficiency and renewable energy programs in place. The annual burden for this collection of information for the states (averaged over the first 3 years following promulgation of this proposed action) is estimated to be a range of 315,554 hours at a total annual labor cost of $22,334,119, to 632,338 hours at a total annual labor cost of $44,755,317. The lower bound estimate reflects the assumption that some states already have energy efficiency and renewable energy programs in place. The higher bound estimate reflects the assumption that no states have energy efficiency and renewable energy programs in place. The total annual burden for the federal government (averaged over the first 3 years following promulgation of this
proposed action) is estimated to be 53,267 hours at a total annual labor cost of $2,958.005Burden 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 19 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 19. Potentially Regulated Categories and Entitiesa

<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

Under Executive Order 13132, EPA may not issue an action that has federalism implications, that imposes substantial direct compliance costs, and that is not required by statute, unless the Federal government provides the funds necessary to pay the direct compliance costs incurred by State and local governments, or the EPA consults with state and local officials early in the process of developing the proposed action.

The EPA has concluded that this action may have federalism implications, because it may impose substantial direct compliance costs on State or local governments, and the Federal government will not provide the funds necessary to pay those costs. As discussed in the Supporting Statement found in the...
The EPA consulted with state and local officials early in the process of developing the proposed action to permit them to have meaningful and timely input into its development. As described in the Federalism discussion in the preamble to the proposed standards of performance for GHG emissions from new EGU's (79 FR 1501, January 8, 2014), the EPA consulted with state and local officials in the process of developing the proposed standards for newly constructed EGU's. This outreach regarded planned actions for new, reconstructed, modified and existing sources. The EPA invited the following 10 national organizations representing state and local elected officials to a meeting on April 12, 2011, in Washington DC: (1) National Governors Association; (2) National Conference of State Legislatures, (3) Council of State Governments, (4) National League of Cities, (5) U.S. Conference of Mayors, (6) National Association of Counties, (7) International City/County Management Association, (8) National Association of Towns and Townships, (9) County Executives of America, and (10) Environmental Council of States.
These 10 organizations representing elected state and local officials have been identified by the EPA as the “Big 10” organizations appropriate to contact for purpose of consultation with elected officials. On February 26, 2014, the EPA re-engaged with those governmental entities to provide a pre-proposal update on the emission guidelines for existing EGUs and emission standards for modified and reconstructed EGUs. In addition, extensive stakeholder outreach conducted by the EPA allowed state leaders, including governors, environmental commissioners, energy officers, public utility commissioners, and air directors, opportunities to engage with EPA officials and provide input regarding reducing carbon pollution from power plants.

A detailed Federalism Summary Impact Statement (FSIS) describing the most pressing issues raised in pre-proposal and post-proposal comments will be forthcoming with the final rule, as required by section 6(b) of Executive Order 13132. In the spirit of Executive Order 13132, and consistent with EPA policy to promote communications between EPA and State and local governments, EPA specifically solicits comment on this proposed action from State and local officials.

F. Executive Order 13175, Consultation and Coordination with Indian Tribal Governments
This action does not have tribal implications, as specified in Executive Order 13175 (65 FR 67249, November 9, 2000). It would not impose substantial direct compliance costs on tribal governments that have affected EGUs located in their area of Indian country. Tribes are not required to, but may, develop or adopt CAA programs. Tribes are not required to develop plans to implement the guidelines under CAA section 111(d) for affected EGUs. To the extent that a tribal government seeks and attains treatment in a manner similar to a state (TAS) status for that purpose and is delegated authority for air quality planning purposes, these proposed emission guidelines would require that planning requirements be met and emission management implementation plans be executed by the tribes. The EPA is aware of three coal-fired EGUs and one natural gas-fired EGU located in Indian country but is not aware of any affected EGUs that are owned or operated by tribal entities. The EPA notes that this proposal does not directly impose specific requirements on EGU sources, including those located in Indian country, such as the three coal-fired EGUs and one natural gas-fired EGU, but provides guidance to any tribe with delegated authority to address 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. In addition, on April 15, 2014, prior to proposal, the EPA met with Navajo Energy Development Group officials. For this proposed action for existing EGUs, a tribe that has one or more affected EGUs located in its area of Indian Country would have the opportunity, but not the obligation, to establish a CO₂ performance standard and a CAA section 111(d) plan for its area of Indian country.

Consultation letters were sent to 584 tribal leaders. The letters provided information regarding the EPA's development of both the NSPS and emission guidelines for fossil fuel-fired EGUs.

The EPA is aware of at least four affected EGUs located in Indian country: two on Navajo lands, the Navajo Generating Station and the Four Corners Generating Station; one on Ute lands, the Bonanza Generating Station; and one on Fort Mojave lands, the South Point Energy Center. The affected EGUs at the first three plants are coal-fired EGUs. The fourth affected EGU is an NGCC facility.
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 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 emission reductions resulting from implementation of the proposed guidelines, as well as substantial ozone and PM₂.₅ emission reductions as a co-benefit, would further improve children’s health.

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

Executive Order 13211 (66 FR 28355; May 22, 2001) requires the EPA to prepare and submit a Statement of Energy Effects to the Administrator of the Office of Information and Regulatory Affairs, OMB, for actions identified as ‘significant energy actions.’ This action, which is a significant regulatory action under EO 12866, is likely to have a significant effect on the supply, distribution, or use of energy. We have prepared a Statement of Energy Effects for this action as follows. We estimate a 4 to 7 percent increase in retail electricity prices on average, across the contiguous U.S. in 2020, and a 16 to 22 percent reduction in coal-fired electricity generation as a result of this rule. The EPA projects that electric power sector delivered natural gas prices will increase by about 8 to 12 percent in 2020. For more information on the estimated energy effects, please refer to the economic impact analysis for this proposal. The analysis is available in the RIA, which is in the public docket.

I. National Technology Transfer and Advancement Act

Section 12(d) of the 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 PM$_{2.5}$ and ozone in the atmosphere, and hazardous air pollutants (HAP), such as mercury. In the final rule revising the annual PM$_{2.5}$ standard, 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. 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

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EGUs whose emissions of one or more of these pollutants or their precursors increase as a result of the proposed emission guidelines for existing fossil fuel-fired EGUs. This may occur at EGUs that are dispatched more intensively than in the past because they become more energy efficient. The EPA has considered the potential for such increases and the environmental justice implications of such increases.

As we noted in the NSR discussion in this preamble, as part of a state’s CAA section 111(d) plan, the state may require an affected EGU to undertake a physical or operational 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. **Because gas-fired EGUs emit essentially no mercury, increased utilization would not increase methylmercury concentrations in their vicinities.** Increased utilization generally would not cause
higher peak concentrations of PM<sub>2.5</sub>, NO<sub>x</sub>, or ozone around such EGUs than is already occurring because peak hourly or daily emissions generally would not change, but increased utilization may make periods of relatively high concentrations more frequent. It should be noted that the gas-fired sources that are likely to be dispatched more frequently than at present have very low emissions of primary particulate matter, SO<sub>2</sub> 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. For natural gas-fired EGUS, the EPA found that regulation of HAP emissions “is not appropriate or necessary because the impacts due to HAP emissions from such units are negligible based on the results of the study documented in the utility RTC” 65 FR 79831. In studies done by DOE/NETL comparing cost and performance of coal- and NG-fired generation, they assumed SO<sub>2</sub>, PM (and Hg) emissions to be “negligible.” Their studies predict NO<sub>x</sub> emissions from a NGCC unit to be approximately 10 times lower than a subcritical or supercritical coal-fired boiler. Many are also very well controlled for emission of NO<sub>x</sub> through the application of after combustion controls such as selective catalytic reduction, although not all gas-fired sources are so equipped. Depending on the specificity of the state CAA section 111(d) plan, the state
may be able to predict which EGUs and communities may be in this type of situation and to address any concerns about localized NO₂ concentrations in the design of the CAA section 111(d) program, or separately from the CAA section 111(d) program but before its implementation. In any case, existing tracking systems will allow states and the EPA to be aware of the EGUs whose utilization has increased most significantly, and thus to be able to prioritize our efforts to assess whether air quality has changed in the communities in the vicinity of such EGUs. There are multiple mechanisms in the CAA to address situations in which air quality has degraded significantly. In conclusion, this proposed rule 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 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 UUUU to read as follows: Subpart UUUU: Emission Guidelines for Greenhouse Gas Emissions and Compliance Times for Electric Utility Generating Units

   Sec. Introduction

   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 emission performance goals?
60.5770 What is the procedure for converting my state rate-based CO₂ emission performance goal to a mass-based CO₂ emission performance goal?
60.5775 What schedules, performance periods, and compliance periods must I include in my state plan?
60.5780 What emission 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 approval criteria for state plans that establish standards of performance limiting the control of greenhouse gas emissions from an
affected steam generating unit, integrated gasification combined cycle (IGCC), or stationary combustion turbine. An affected steam generating unit, IGCC, or stationary combustion turbine shall, for the purposes of this subpart, be referred to as an affected EGU. These emission guidelines are developed in accordance with sections 111(d) of the Clean Air Act and subpart B of this part. To the extent any requirement of this subpart is inconsistent with the requirements of 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)(11) of this section in your state plan.

Deleted: 10
(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 emission performance level for affected entities that will be achieved through implementation of the plan.

   (i) The plan must specify the average emissions performance that the plan will achieve for the following periods:

   (A) The 10 year interim plan performance period of 2020 through 2029.

   (B) The single projection year of 2030.

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

(A) For a rate-based CO₂ emission 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.

(B) For a mass-based CO₂ emission performance level, the identified level of performance must represent the total tons of CO₂ that will be emitted by affected entities during each plan performance period.

(iii) For the interim plan performance period you must identify the emission performance levels anticipated under the plan during each year 2020 through 2029.

(4) A demonstration that the plan is projected to achieve each of the state’s emission performance levels for affected entities according to paragraph (a)(3) of this section.

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

(6) A demonstration that each emission standard is quantifiable, non-duplicative, permanent, verifiable, and enforceable with respect to an affected entity.
(7) If your state plan does not require achievement of the full level of required emission performance, and the identified interim increments of performance in section (a)(3)(iii), through emission limits on EGUs, the plan must specify the following:

(i) Program implementation milestones (e.g., start of an end-use energy efficiency program, retirement of an affected EGU, or increase in portfolio requirements under a renewable portfolio standard) and milestone dates that are appropriate to the requirements, programs, and measures included in the plan.

(ii) Corrective measures that will be implemented in the event that the comparison required by § 60.5815(b) of projected versus actual emissions performance of affected entities shows that actual emissions performance is greater than 10 percent in excess to projected plan performance for the period described in § 60.5775(c)(1), and a process and schedule for implementing such corrective measures.

(8) Identification of applicable monitoring, reporting, and recordkeeping requirements for each affected entity. If applicable, these requirements must be consistent with the requirements specified in § 60.5810.

(9) Description of the process, contents, and schedule for annual state reporting to the EPA about plan implementation and progress including information required under § 60.5815.
(10) Certification that the hearing on the state plan was held, a list of witnesses and their organizational affiliations, if any, appearing at the hearing, and a brief written summary of each presentation or written submission.

(11) Supporting material including:

(i) Materials demonstrating the state's legal authority to carry out each component of its plan, including emissions standards;

(ii) Materials supporting the projected emissions performance level that will be achieved by affected entities under the plan, according to paragraph (a)(4);

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

(iii) 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?

(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 the 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 CO₂ 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 CO₂ 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) If a state needs additional time to submit a complete plan, then the state must notify the EPA by letter of such intent by no later than April 1, 2016. In this letter, the state must 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, listed in paragraph (b) of this section, by June 30, 2016.

(b) You must include the following required elements in an initial submittal in lieu of a complete state plan if your request for extension in paragraph (a) of this section has been approved:

1. A description of the plan approach and progress made to date in developing each of the plan elements in § 60.5740;

2. An initial projection of the level of emission performance that will be achieved 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 emission performance;
implementing legislation, regulations and agreements; necessary approvals);

(6) Identification of existing and future programs, requirements, and measures the state intends to include in the plan;

(7) If a multi-state plan is being developed, an executed agreement(s) with other states (e.g., MOU) participating in the development of the multistate plan; and

(8) A commitment to submit a complete plan by June 30, 2017, for a single-state plan, or June 30, 2018, for a multi-state plan, and actions the state will take to show progress in addressing incomplete plan components prior to submittal of the complete plan.

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

(a) The annual average state rate-based CO₂ emission performance goals for the interim performance periods of 2020 through 2029, and the final 2030 and thereafter period are respectively listed in Table 1 of this Subpart. The state rate-based CO₂ emission performance goal may be converted to a mass-based emission 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 emissions that are projected to be emitted by affected EGUs, in the absence of emission standards contained in the plan, if the affected EGUs were to perform at an average lb 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, as defined in section § 60.5820, for each affected entity regulated under the plan.

(c) For the interim performance period of 2020-2029 your state must meet the requirements in paragraphs (c)(1) and (c)(2) of this section.

(1) Your state plan must include increments of emissions performance (either rate based or mass based with respect to the interim level of performance set in the state plan) within the interim performance period for every 2-rolling calendar years starting January 1, 2020 and ending in 2028 (i.e. 2020-2022, 2021-2023, 2022-2024, etc.), unless other periods that ensure regular progress in the interim period are approved by the Administrator.

2) At the end of 2029 your state must meet the interim emissions performance level specified in § 60.5740(a)(3) as averaged over the plan performance period 2020-2029.

(d) During the final performance period, 2030 and thereafter, your state must meet the final emission performance level specified in § 60.5740(a)(3) on a 3-calendar year rolling average starting January 1, 2030 (i.e., 2030-2032, 2031-2033, 2032-2034, etc.).

(e) You must include the provisions of your state plan which demonstrate progress and compliance with the requirements.
§ 60.5780 What emissions standards and enforcing measures must I include in my plan?

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

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

(c) An emission standard is verifiable with respect to an affected entity if adequate monitoring, recordkeeping and reporting requirements are in place to enable the state and the Administrator to independently evaluate, measure, and verify compliance with the emission standard.

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

(e) An emission standard is permanent with respect to an affected entity if the emission standard must be met for each compliance period, or unless it is replaced by another emission.
standard in an approved plan revision, or the state demonstrates in an approved plan revision that the emissions reductions from the emission standard are no longer necessary for the state to meet its state level of performance.

(f) An emission standard is enforceable against an affected entity if:

1. A technically accurate limitation or requirement and the time period for the limitation or requirement is specified;
2. Compliance requirements are clearly defined;
3. The affected entities responsible for compliance and liable for violations can be identified;
4. Each compliance activity or measure is enforceable as a practical matter; and
5. The Administrator and the state maintain the ability to enforce violations and secure appropriate corrective actions pursuant to Sections 113(a) - (h) of the Act.

§ 60.5785 What is the procedure for revising my state plan?

State plans can only be revised with approval by the Administrator. If one (or more) of the elements of the state plan set in § 60.5740 require revision with respect to reaching the emission performance goal set in § 60.5765 a request may be submitted to the Administrator indicating the proposed corrections to the state plan to ensure the emission performance goal is met.
§ 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 EPA approving 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 emission standard they must prepare a monitoring plan in accordance with the applicable provisions in § 75.53(g) and (h) of this chapter.

(2) An affected EGU must measure the hourly 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 (Fₜₐ) using Equation F-7b in section 3.3.6 of appendix F to part 75 of this chapter, and may use these Fₜₐ values in the emissions calculations instead of using the default Fₜₐ 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 CO\textsubscript{2} mass emissions measured at the individual stacks or ducts and dividing by the net energy output for the affected EGU.

(b) An affected EGU must maintain records for at least 10 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

(1) An affected EGU must maintain each record on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to § 60.7. An affected EGU may maintain the records off site and electronically for the remaining year(s).

(c) An affected EGU must include in a report required by the state plan covering each compliance period to the delegated authority all hourly CO\textsubscript{2} emissions and all hourly net electric output and all hourly net energy output measurements for a CHP facility calculated from data monitored according to paragraph (a) of this section.

Recordkeeping and Reporting Requirements

§ 60.5810 What are my state recordkeeping requirements?

(a) States must keep records of all plan components, plan requirements, supporting documentation, and the status of meeting the plan requirements defined in the state plan on an annual basis during the interim plan performance period from 2020-2029. After 2029 states must keep records of all
information that is used to support any continued effort to meet the final emissions performance goal.

(b) States must keep records of all data submitted by each affected entity that is used to determine compliance with each affected entity’s emissions standard.

(c) If a state has a requirement for hourly 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 an annual report covering each calendar year no later than July 1 of the following year, starting July 1, 2021. The annual report must include the following:

(1) The level of emissions performance achieved by all affected entities and identification of whether affected entities are on schedule to meet the applicable level of emissions performance for affected entities during the plan performance period and compliance periods, as specified in the plan.
(2) The level of emissions performance achieved by all affected EGUs during the reporting period, and prior reporting periods, expressed as average 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.

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

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

(5) All other required information, as specified in your state plan according to §60.5740(a)(9).

(6) All information required by §60.5775(e).

(b) For each two-year period in §60.5775(c)(1), you must compare the CO₂ emission performance achieved by affected EGU in the state versus the CO₂ emission performance projected in the state plan. If actual emission performance is greater than 10 percent in excess to projected plan performance for a two-year comparison period, you must explain the reasons for the deviation and specify the corrective actions that will be taken to ensure that the required interim and final levels of emission
performance in the plan will be met. The information required in this paragraph must be included in the annual report required by paragraph (a) of this section.

(c) You must include in your 2029 annual report (which is subsequently due by July 1, 2030) the calculation of average emissions over the 2020-2029 interim performance period used to determine compliance with your interim emission performance level. The calculated value must be in units consistent with your interim emission performance level.

(d) You must include in each report, starting with the 2032 annual report (which is subsequently due by July 1, 2033), a 3-calendar year rolling average used to determine compliance with the final emission performance level. The calculated value must be in units consistent with your final emission performance level.

Definitions

§ 60.5820 What definitions apply to this subpart?

As used in this subpart, all terms not defined herein will have the meaning given them in the Clean Air Act and in subparts A (General Provisions 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 for fossil fuel of greater than 73 MW (250 MMBtu/h), that was constructed for the purpose of supplying more than 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 for fossil fuel of greater than 73 MW (250 MMBtu/h) and that was constructed for the purpose of supplying more than 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).
. In this rulemaking, the EPA is following the regulatory requirements 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 guidelines, including adhering to their stringency.

, in developing state plans. These requirements authorize the EPA to develop emission reduction goals based on the application of

and, for this rulemaking, the following factors are key
the two basic types of approaches to reducing

affected EGUs (e.g., by improving heat rates

switching to lower carbon fuels) and limiting emissions of

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CO₂ emissions by replacing generation at high carbon-intensity affected EGUs with generation from lower-carbon generation from existing NGCC units.¹ From a technical perspective, the same potential would exist to replace high-emitting generation with generation from additional NGCC capacity that may be built in the future; the analysis above regarding the feasibility of policies to increase utilization rates of existing NGCC units on average to 70 percent applies equally to new NGCC units.² We view the opportunity to reduce CO₂ emissions at affected EGUs by means of addition and operation of new NGCC capacity as clearly feasible.

Compared to the opportunity to reduce CO₂ 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,

¹ For purposes of this proposal, NGCC units that have commenced construction as of January 8, 2014 are "existing" units.
² Whether and to what extent adding new NGCC capacity is likely to lead to CO₂ 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 CO₂ emissions.
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\textsubscript{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\textsubscript{2} reductions at affected EGUs, some portion of their construction or fixed operating costs might also be attributable to the CO\textsubscript{2} reduction opportunity, increasing to some uncertain extent the cost of the CO\textsubscript{2} reductions at affected EGUs achieved through re-dispatch to those new NGCC units.

Unlike generation from other types of potential new generating capacity such as wind, solar, and nuclear capacity, NGCC generation does produce CO\textsubscript{2} 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 CO\textsubscript{2} 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?

The third basic category of approaches that create a basis for incorporating limiting utilization, and therefore limiting emissions, as an

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 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 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.

" 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 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 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 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 CO₂. 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.


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

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, 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.6

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

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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.

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.

7 Participating states include Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont; RGGI website: http://www.rggi.org/rggi
9 – Summary of Climate and Air Pollutant Emission Reductions with Alternative Option 2 - 2020

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Table 10 – Summary of Climate and Air Pollutant Emission Reductions with Alternative Option 2 - 2025

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